CABOT OIL & GAS CORP
Form 10-K/A
March 02, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K/A
Amendment No. 1
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
Commission file number 1-10447
CABOT OIL & GAS CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	04-3072771
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas 77024
(Address of principal executive offices including ZIP code)
(281) 589-4600
(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, par value $.10 per share	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 ý 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 ý
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 and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o
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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 ý.
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an 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. (Check one):

Large accelerated filer	ý	Accelerated filer	o	Non-accelerated filer (Do not check if a smaller reporting company)	o	Smaller reporting company	o	Emerging growth company	o

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

Exchange Act. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No ý

The aggregate market value of Common Stock, par value $.10 per share ("Common Stock"), held by non-affiliates as of the last business day of registrant's most recently completed second fiscal quarter (based upon the closing sales price on the New York Stock Exchange on June 30, 2017) was approximately $11.4 billion.

As of February 16, 2018, there were 460,786,236 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 2, 2018 are incorporated by reference into Part III of this report.

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EXPLANATORY NOTE

Cabot Oil & Gas Corporation (the Company) filed its Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (Original Filing) with the U.S. Securities and Exchange Commission (SEC) on February 28, 2018. The Company is filing this Amendment No. 1 (Amendment) to its Original Filing solely to revise a typographical error in a date contained in the Report of Independent Registered Public Accounting Firm related to their Opinion on the Financial Statements and Internal Control over Financial Reporting. In that report, the date of the Opinion was inadvertently referenced as February 27, 2018. The correct date of their Opinion is February 28, 2018. That error has been corrected in this Amendment.

In addition, pursuant to the rules of the SEC, the exhibit list included in Item 15 of Part IV of the Original Filing has been amended to contain currently-dated certifications from the Company's Chief Executive Officer and Chief Financial Officer, as required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002. The certifications of the Company's Chief Executive Officer and Chief Financial Officer are attached as exhibits to this Amendment.

Except as described above, this Amendment does not amend or update any other information contained in the Original Filing. The Company has included a complete copy of the Original Filing, as amended per above, in this filing.

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FORWARD-LOOKING INFORMATION

The statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging and risk management activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "target," "predict," "may," "should," "could," "will" and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and crude oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches and other factors detailed herein and in our other Securities and Exchange Commission filings. See "Risk Factors" in Item 1A for additional information about these risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and included within this Annual Report on Form 10-K:

Abbreviations

Bbl.   One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.
Bcf.   One billion cubic feet of natural gas.
Bcfe.   One billion cubic feet of natural gas equivalent.
Btu.   One British thermal unit.
Dth.   One million British thermal units.
Mbbls.   One thousand barrels of oil or other liquid hydrocarbons.
Mcf.   One thousand cubic feet of natural gas.
Mcfe.   One thousand cubic feet of natural gas equivalent.
Mmbbls.   One million barrels of oil or other liquid hydrocarbons.
Mmbtu.   One million British thermal units.
Mmcf.   One million cubic feet of natural gas.
Mmcfe.   One million cubic feet of natural gas equivalent.
NGL.   Natural gas liquids.
NYMEX.   New York Mercantile Exchange.

Definitions

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

Conventional play.   A term used in the oil and gas industry to refer to an area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps utilizing conventional recovery methods.

Developed reserves.   Developed reserves are 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 costs.   Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating

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

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.

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Dry hole. Exploratory or development well that does not produce oil or gas in commercial quantities.

Exploitation activities. The process of the recovery of fluids from reservoirs and drilling and development of oil and gas reserves.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (i) costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs, (ii) costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records, (iii) dry hole contributions and bottom hole contributions, (iv) costs of drilling and equipping exploratory wells, and (v) costs of drilling exploratory-type stratigraphic test wells.

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. Generally, an exploratory well is any well that is not a development well, an extension well, or a service well.

Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

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

Gross acres. The total acres in which a working interest is owned.

Gross wells. The total wells in which a working interest is owned.

Net acres. The number of acres an owner has out of a particular number of gross acres. An owner who has a 30% working interest in 100 acres owns 30 net acres.

Net wells. The percentage ownership interest in a well than an owner has based on the working interest. An owner who has a 30% working interest in a well owns a 0.30 net well.

Oil. Crude oil and condensate.

Operator. The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

Play. A geographic area with potential oil and gas reserves.

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Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.
Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely not to be recovered.
Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities, which become part of the cost of oil and gas produced.
Proved properties. Properties with proved reserves.
Proved reserves. Proved reserves are those quantities, 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 and operating methods prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-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.
Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.
Reliable technology. A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonable certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.
Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.
Royalty interest. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowners' royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.
Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud.
Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of future price changes to the extent provided by contractual

arrangements in existence at year-end), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are

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calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

Unconventional play. A term used in the oil and gas industry to refer to a play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds or (3) shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to achieve economic flow rates.

Undeveloped reserves. Undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence exists that establishes reasonable certainty of economic producibility at greater distances. 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. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved reserves.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

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PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Cabot Oil & Gas Corporation is an independent oil and gas company engaged in the development, exploitation and exploration of oil and gas properties. Our assets are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. We operate in one segment, natural gas and oil development, exploitation, exploration and production, in the continental United States. We have offices located in Houston, Texas and Pittsburgh, Pennsylvania.

STRATEGY

Our objective is to enhance shareholder value over the long-term. We believe this is attainable by employing disciplined management of our balance sheet and our operations and remaining focused on our core asset base. Key components of our business strategy include:

- maintaining a conservative financial position and financial flexibility,
- providing returns-focused production and reserve growth within operating cash flows,
- continuing to return capital to shareholders through dividends and share repurchases, and
- continuing to optimize drilling and completion efficiencies while leveraging our technical expertise to achieve cost reductions and improved efficiencies

These strategies will be achieved through further growth and development of our cornerstone assets in the Marcellus Shale in northeast Pennsylvania which represent 96% percent of our equivalent proved reserves as of December 31, 2017. While we remain focused on the growth and development of our Marcellus Shale asset, we also look for other development and exploration opportunities that will contribute to our overall strategy.

2018 OUTLOOK

Our 2018 drilling program includes approximately $890.0 million in capital expenditures and approximately $60.0 million in expected contributions to our equity method investments. We expect to fund these expenditures with existing cash, operating cash flow and, if required, borrowings under our revolving credit facility. See Note 4 of the Notes to the Consolidated Financial Statements for further details regarding our equity method investments in Constitution Pipeline Company, LLC (Constitution) and Meade Pipeline Co LLC (Meade).

In 2018, we plan allocate the majority of our capital to the Marcellus Shale, where we expect to drill 85 gross wells (85.0 net) and complete 95 gross wells (95.0 net). We allocate our planned program for capital expenditures based on market conditions, return expectations and availability of services and human resources. We will continue to assess the natural gas price environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

As a result of the expected in-service of various infrastructure projects, including the Atlantic Sunrise pipeline, during 2018, we increased our budgeted capital expenditures compared to 2017. We plan to operate an average of approximately 3.0 rigs in the Marcellus Shale in 2018.

DESCRIPTION OF PROPERTIES

Our exploration, development and production operations are primarily concentrated in one unconventional play—the Marcellus Shale in northeast Pennsylvania. We also have operations in various other unconventional plays throughout the continental United States.

Marcellus Shale

Our Marcellus Shale properties represent our primary operating and growth area in terms of reserves, production and capital investment. Our properties are principally located in Susquehanna County, Pennsylvania, where we currently hold approximately 172,000 net acres in the dry gas window of the play. Our 2017 net production in the Marcellus Shale was 641.7 Bcfe, representing approximately 94% of our total equivalent production for the year. As of December 31, 2017, we had a total of 609.3 net wells in the Marcellus Shale, of which approximately 99% are operated by us.

During 2017, we invested $407.9 million in the Marcellus Shale and drilled or participated in drilling 55.9 net wells, completed 54.2 net wells and turned in line 53.0 net wells. As of December 31, 2017, we had 27.0 net wells that were either in

the completion stage or waiting on completion or connection to a pipeline. We exited 2017 with two drilling rigs operating in the play and plan to exit 2018 with three rigs operating.

Other Properties

Eagle Ford Shale - Our properties in the Eagle Ford Shale are principally located in Atascosa, Frio and La Salle Counties, Texas, where we hold approximately 79,000 net acres in the oil window of the play. In 2017, our net crude oil/condensate/NGL and natural gas production from the Eagle Ford Shale was 4,939 Mbbl and 3.3 Bcf, respectively, or 33.0 Bcfe, representing approximately 5% of our total equivalent production. As of December 31, 2017, we had a total of 270.0 net wells in the Eagle Ford, of which approximately 90% are operated by us.

On December 19, 2017, we entered into an agreement to sell our operated and non-operated Eagle Ford Shale assets to an affiliate of Venado Oil & Gas LLC for $765.0 million, subject to customary closing conditions and purchase price adjustments. We expect to close this transaction in the first quarter of 2018.

Other Properties - We also operate or participate in other unconventional plays throughout the continental United States, including the Haynesville, Bossier, and James Lime formations in east Texas; and the Utica Shale in Pennsylvania.

On December 11, 2017, we entered into an agreement to sell our operated and non-operated Haynesville Shale assets to an undisclosed buyer for $30.0 million, subject to customary closing conditions and purchase price adjustments. We expect to close this transaction in the first half of 2018.

ACQUISITIONS

In December 2014, we completed the acquisition of certain proved and unproved oil and gas properties located in the Eagle Ford Shale in south Texas for $30.5 million. Total cash consideration paid was $29.9 million, which reflects the impact of customary purchase price adjustments and acquisition costs.

In October 2014, we purchased certain proved and unproved oil and gas properties located in the Eagle Ford Shale in south Texas for $210.0 million. Total cash consideration paid at closing was $185.2 million, which reflects the impact of customary purchase price adjustments and acquisition costs. In April 2015, we completed the acquisition of the remaining oil and gas properties for which the seller was unable to obtain consents at closing for $16.0 million.

DIVESTITURES

In September 2017, we sold certain proved and unproved oil and gas properties and related pipeline assets located in West Virginia, Virginia and Ohio to a third party for $41.3 million. During the second quarter of 2017, we recorded an impairment charge of $68.6 million associated with the proposed sale of these properties and upon closing the sale in the third quarter of 2017, we recognized a loss on sale of oil and gas properties of $11.9 million.

In February 2016, we sold certain proved and unproved oil and gas properties in east Texas to a third party for $56.4 million and recognized a $0.5 million gain on sale of assets.

In October 2014, we sold certain proved and unproved oil and gas properties in east Texas to a third party for $44.3 million and recognized a $19.9 million gain on sale of assets.

In December 2013, we sold certain proved and unproved oil and gas properties located in the Oklahoma and Texas panhandles to Chaparral Energy, L.L.C. for $160.0 million and recognized a $19.4 million gain on sale of assets. We also sold certain proved and unproved oil and gas properties located in Oklahoma, Texas and Kansas to a third party for $123.4 million and recognized a $17.5 million loss on sale of assets.

In 2013, we sold various other proved and unproved oil and gas properties for $44.3 million and recognized an aggregate net gain of $19.5 million.

MARKETING

Substantially all of our natural gas is sold at market sensitive prices under both long-term and short-term sales contracts and is subject to seasonal price swings. The principal markets for our natural gas are in the northeastern United States where we sell natural gas to industrial customers, local distribution companies, gas marketers and power generation facilities.

We also incur transportation and gathering expenses to move our natural gas production from the wellhead to our principal markets in the United States. The majority of our natural gas production is transported on third-party gathering

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systems and interstate pipelines where we have long-term contractual capacity arrangements or use purchaser-owned capacity under both long-term and short-term sales contracts.

To date, we have not experienced significant difficulty in transporting or marketing our natural gas production as it becomes available; however, there is no assurance that we will always be able to transport and market all of our production.

Our crude oil is sold at market sensitive prices under long-term sales contracts. The principal markets for our oil are in the south Texas refining region where we can market to refineries and oil pipeline customers.

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell natural gas. We believe we will have sufficient production quantities to meet substantially all of our commitments, but may be required to purchase natural gas from third parties to satisfy shortfalls should they occur.

A summary of our firm sales commitments as of December 31, 2017 are set forth in the table below:

	Natural Gas (Bcfe)
2018	294.0
2019	614.8
2020	614.8
2021	575.0
2022	561.7

We utilize a part of our firm transportation capacity to deliver natural gas under the majority of these firm sales contracts and have entered into numerous agreements for transportation of our production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms. However, we do not believe we have a financial commitment due based on our current proved reserves and production levels from which we can fulfill these obligations.

RISK MANAGEMENT

From time to time, we use derivative financial instruments to manage price risk associated with our natural gas and crude oil production. While there are many different types of derivatives available, we generally utilize collar, swap and basis swap agreements designed to manage price risk more effectively. The collar arrangements are a combination of put and call options used to establish floor and ceiling prices for a fixed volume of natural gas or crude oil production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The swap agreements call for payments to, or receipts from, counterparties based on whether the index price for the period is greater or less than the fixed price established for the particular period under the swap agreement.

During 2017, natural gas collars with floor prices of $3.09 per Mcf and ceiling prices ranging from $3.42 to $3.45 per Mcf covered 35.5 Bcf, or 5% of natural gas production at an average price of $3.20 per Mcf. Natural gas swaps covered 51.7 Bcf, or 8%, of natural gas production at a weighted-average price of $3.23 per Mcf. Crude oil collars with floor prices of $50.00 per Bbl and ceiling prices ranging from $56.25 to $56.50 per Bbl covered 1.8 Mmbbl, or 41%, of crude oil production at a weighted-average price of $51.78 per Bbl.

As of December 31, 2017, we had the following outstanding financial commodity derivatives:

			Collars				
			Floor		Ceiling		Basis Swaps
Type of Contract	Volume	Contract Period	Range	Weighted-Average	Range	Weighted-Average	Weighted-Average
Financial contracts							
Natural gas (Leidy)	17.7 Bcf	Jan. 2018 - Dec. 2018					$(0.71)
Natural gas (Transco)	21.3 Bcf	Jan. 2018 - Dec. 2019					$0.42

Crude oil (WTI/LLS)	2.9	Mmbbl	Jan. 2018 - Dec. 2018	$—	$55.00	$63.35-$63.80	$63.62

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In January 2018, we entered into the following financial commodity derivatives:

Type of Contract	Volume	Contract Period	Swaps Weighted- Average	Basis Swaps Weighted- Average
Financial contracts				
Natural gas (NYMEX)	84.4 Bcf	Feb. 2018 - Dec. 2018	$2.93	
Natural gas (NYMEX)	13.3 Bcf	Feb. 2018 - Oct. 2018	$3.10	
Natural gas (Leidy)	16.2 Bcf	Feb. 2018 - Dec. 2018		$(0.68)

In the tables above, natural gas prices are stated per Mcf and crude oil prices are stated per barrel.

While we have hedged a portion of our expected natural gas and crude oil production for 2018 and beyond, any unhedged production is directly exposed to the volatility in natural gas and crude oil market prices, whether favorable or unfavorable. We will continue to evaluate the benefit of using derivatives in the future. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures about Market Risk" for further discussion related to our use of derivatives.

As of December 31, 2017, we had the following outstanding physical commodity derivatives:

Type of Contract	Volume		Contract Period	Weighted-Average Fixed Price
Physical contracts				
Natural gas purchase	81.2	Bcf	Jan. 2018 - Oct. 2018	$3.70
Natural gas sales	11.7	Bcf	Jan. 2018 - Feb. 2018	$4.71

In the table above, natural gas prices are stated per Mcf.

In January 2018, we terminated certain physical purchase contracts prior to their settlement date. The termination did not have a material impact on the Consolidated Financial Statements, as the contracts were previously recognized at fair value.

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RESERVES

The following table presents our estimated proved reserves for the periods indicated:

	December 31,		
	2017	2016	2015
Natural Gas (Bcf)			
Proved developed reserves	6,001	5,500	4,676
Proved undeveloped reserves(1)	3,352	2,781	3,180
	9,353	8,281	7,856
Crude Oil & NGLs (Mbbl)(2)			
Proved developed reserves	31,066	20,442	25,586
Proved undeveloped reserves(1)	31,186	28,730	30,144
	62,252	49,172	55,730
Natural gas equivalent (Bcfe)(3)	9,726	8,576	8,190
Reserve life index (in years)(4)	14.2	13.7	13.6

(1) Proved undeveloped reserves for 2017, 2016 and 2015 include reserves drilled but uncompleted of 807.4 Bcfe, 488.7 Bcfe and 937.4 Bcfe, respectively.

(2) NGL reserves were less than 1.0% of our total proved equivalent reserves for 2017, 2016 and 2015, and 13.7%, 13.6% and 16.1% of our proved crude oil and NGL reserves for 2017, 2016 and 2015, respectively.

(3) Natural gas equivalents are determined using a ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or NGLs.

(4) Reserve life index is equal to year-end proved reserves divided by annual production for the years ended December 31, 2017, 2016 and 2015, respectively.

Our proved reserves totaled approximately 9,726 Bcfe at December 31, 2017, of which 96% were natural gas. This reserve level was up by 13% from 8,576 Bcfe at December 31, 2016. In 2017, we added 1,236.1 Bcfe of proved reserves through extensions, discoveries and other additions, primarily due to the positive results from our drilling and completion program in the Dimock field in northeast Pennsylvania. We also had a net upward revision of 928.5 Bcfe, which was due to an upward performance revision of 863.8 Bcfe primarily associated with positive drilling results in our Dimock field in northeast Pennsylvania and 103.0 Bcfe associated with higher commodity prices, partially offset by a downward revision of 38.3 Bcfe associated with proved undeveloped (PUD) reserves reclassifications as a result of the five year limitation. In 2017, we produced 685.3 Bcfe.

Our reserves are sensitive to natural gas and crude oil prices and their effect on the economic productive life of producing properties. Our reserves are based on the 12-month average natural gas, crude oil and NGL index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during the year. Increases in commodity prices may result in a longer economic productive life of a property or result in more economically viable proved undeveloped reserves to be recognized. Decreases in prices may result in negative impacts of this nature.

For additional information regarding estimates of proved reserves, the audit of such estimates by Miller and Lents, Ltd. (Miller and Lents) and other information about our reserves, including the risks inherent in our estimates of proved reserves, see the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8 and “Risk Factors-Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated” in Item 1A.

Technologies Used In Reserves Estimates

We utilize various traditional methods to estimate our natural gas, crude oil and NGL reserves, including decline curve extrapolations, volumetric calculations and analogies, and in some cases a combination of these methods. In addition, at times we may use seismic interpretations to confirm continuity of a formation in combination with traditional technologies; however, seismic interpretations are not used in the volumetric computation.

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Internal Control

Our Senior Vice President, South Region and Engineering is the technical person responsible for our internal reserves estimation process and provides oversight of our corporate reservoir engineering department, which consists of three engineers, and the annual audit of our year-end reserves by Miller and Lents. He has a Bachelor of Science degree in Chemical Engineering, specializing in petroleum engineering, and over 35 years of industry experience with positions of increasing responsibility in operations, engineering and evaluations. He has worked in the area of reserves and reservoir engineering for 26 years and is a member of the Society of Petroleum Engineers.

Our reserves estimation process is coordinated by our corporate reservoir engineering department. Reserve information, including models and other technical data, are stored on secured databases on our network. Certain non-technical inputs used in the reserves estimation process, including commodity prices, production and development costs and ownership percentages, are obtained by other departments and are subject to testing as part of our annual internal control process. We also engage Miller and Lents, independent petroleum engineers, to perform an independent audit of our estimated proved reserves. Upon completion of the process, the estimated reserves are presented to senior management.

Miller and Lents made independent estimates for 100% of our proved reserves estimates and concluded, in their judgment, we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues. Further, Miller and Lents has concluded (1) the reserves estimation methods employed by us were appropriate, and our classification of such reserves was appropriate to the relevant SEC reserve definitions, (2) our reserves estimation processes were comprehensive and of sufficient depth, (3) the data upon which we relied were adequate and of sufficient quality, and (4) the results of our estimates and projections are, in the aggregate, reasonable. A copy of the audit letter by Miller and Lents dated January 26, 2018, has been filed as an exhibit to this Form 10-K.

Qualifications of Third Party Engineers

The technical person primarily responsible for the audit of our reserves estimates at Miller and Lents meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Miller and Lents is an independent firm of petroleum engineers, geologists, geophysicists, and petro physicists; they do not own an interest in our properties and are not retained on a contingent fee basis.

Proved Undeveloped Reserves

At December 31, 2017 we had 3,538.7 Bcfe of PUD reserves associated with future development costs of $1.5 billion, which represents an increase of 585.4 Bcfe compared to December 31, 2016. Approximately 94% of our PUD reserves are located in Susquehanna County, Pennsylvania. We expect to complete approximately 100% of our PUD reserves associated with drilled but uncompleted wells by the end of 2018. Future development plans are reflective of the expected increase in commodity prices and have been established based on cash on hand, expected available cash flows from operations and availability under our revolving credit facility. As of December 31, 2017, all PUD reserves are expected to be drilled and completed within five years of initial disclosure of these reserves.

The following table is a reconciliation of the change in our PUD reserves (Bcfe):

	Year Ended December 31, 2017
Balance at beginning of period	2,953.3
Transfers to proved developed	(1,217.2)
Additions	1,030.2
Revision of prior estimates	772.4
Balance at end of period	3,538.7

Changes in PUD reserves that occurred during the year were due to:

- transfer of 1,217.2 Bcfe from PUD to proved developed reserves based on total capital expenditures of $382.4 million during 2017;

- new PUD reserve additions of 1,030.2 Bcfe primarily in the Dimock field in northeast Pennsylvania; and

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- positive PUD reserve revisions of 772.4 Bcfe resulting from positive performance revisions of 809.8 Bcfe associated with the drilling of longer lateral wells and completing more frac stages in our Dimock field in northeast Pennsylvania and positive price revisions of 0.9 Bcfe, partially offset by downward revisions of 38.3 Bcfe associated with PUD reclassifications as a result of the five year limitation.

PRODUCTION, SALES PRICE AND PRODUCTION COSTS

The following table presents historical information about our production volumes for natural gas and oil (including NGLs), average natural gas and crude oil sales prices, and average production costs per equivalent, including our Dimock field located in northeast Pennsylvania, which represents more than 15% of our total proved reserves:

	Year Ended December 31,		
	2017	2016	2015
Production Volumes			
Natural gas (Bcf)			
Dimock field	641.7	581.9	540.8
Total	655.6	600.4	566.0
Oil (Mbbl)(1)			
Total	4,953	4,454	6,096
Equivalents (Bcfe)			
Dimock field	641.7	581.9	540.8
Total	685.3	627.1	602.5
Natural Gas Average Sales Price ($/Mcf)			
Dimock field	$2.33	$1.69	$1.78
Total (excluding realized impact of derivative settlements)	$2.30	$1.70	$1.81
Total (including realized impact of derivative settlements)	$2.31	$1.70	$2.15
Oil Average Sales Price ($/Bbl)			
Total (excluding realized impact of derivative settlements)	$47.81	$37.65	$45.72
Total (including realized impact of derivative settlements)	$48.16	$37.30	$45.72
Average Production Costs ($/Mcfe)			
Dimock field	$0.04	$0.03	$0.04
Total	$0.11	$0.11	$0.18

(1) Includes NGLs which represent less than 1.0% of our equivalent production for all years presented and 10.3%, 9.9%, and 11.0% of our crude oil production for the years ended December 31, 2017, 2016 and 2015, respectively.

ACREAGE

Our interest in both developed and undeveloped properties is primarily in the form of leasehold interests held under customary mineral leases. These leases provide us the right to develop oil and/or natural gas on the properties. Their primary terms range in length from approximately three to 10 years. These properties are held for longer periods if production is established.

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The following table summarizes our gross and net developed and undeveloped leasehold and mineral fee acreage at December 31, 2017:

	Developed		Undeveloped [1]		Total	
	Gross	Net	Gross	Net	Gross	Net
Leasehold acreage	382,900	301,230	876,380	780,960	1,259,280	1,082,190
Mineral fee acreage	75	19	170,054	148,120	170,129	148,139
Total	382,975	301,249	1,046,434	929,080	1,429,409	1,230,329

(1) Includes leasehold and mineral fee net acreage of 606,959 and 147,812, respectively, associated with deep formations located in West Virginia and Virginia that were retained as part of the divestiture that closed in the third quarter of 2017. All of this acreage is held by production from the shallow formations.

Total Net Undeveloped Acreage Expiration

In the event that production is not established or we take no action to extend or renew the terms of our leases, our net undeveloped acreage that will expire over the next three years as of December 31, 2017 is 36,983, 10,880 and 34,380 for the years ending December 31, 2018, 2019 and 2020, respectively.

We expect to retain substantially all of our expiring acreage either through drilling activities, renewal of the expiring leases or through the exercise of extension options. As of December 31, 2017, approximately 23% of our expiring acreage disclosed above is located in our primary areas of operation where we currently expect to continue development activities and/or extend the lease terms.

WELL SUMMARY

The following table presents our ownership in productive natural gas and crude oil wells at December 31, 2017. This summary includes natural gas and crude oil wells in which we have a working interest:

	Gross	Net
Natural gas	803	709.9
Crude oil	309	268.7
Total[1]	1,112	978.6

(1) Total percentage of gross operated wells is 85.3%.

DRILLING ACTIVITY

We drilled and completed wells or participated in the drilling and completion of wells as indicated in the table below. The information below should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	104	93.2	76	76.0	106	97.9
Dry	—	—	—	—	—	—
Exploratory Wells						
Productive	—	—	—	—	1	1.0
Dry	1	1.0	—	—	—	—
Total	105	94.2	76	76.0	107	98.9
Acquired Wells	—	—	—	—	1	1.0

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During the year ended December 31, 2017, we completed 50 gross wells (44.3 net) that were drilled in prior years. The following table sets forth information about wells for which drilling was in progress or which were drilled but uncompleted at December 31, 2017, which are not included in the above table:

	Drilling In Progress		Drilled But Uncompleted	
	Gross	Net	Gross	Net
Development wells	4	4.0	36	32.6
Exploratory wells	3	3.0	—	—
Total	7	7.0	36	32.6

OTHER BUSINESS MATTERS

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes or development obligations under oil and gas leases. As is customary in the industry in the case of undeveloped properties, preliminary investigations of record title are made at the time of lease acquisition. Complete investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Competition

The oil and gas industry is highly competitive and we experience strong competition in our primary producing areas. We primarily compete with integrated, independent and other energy companies for the sale and transportation of our oil and natural gas production to marketing companies and end users. Furthermore, the oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial and residential consumers. Many of these competitors have greater financial, technical and personnel resources. The effect of these competitive factors cannot be predicted.

Price, contract terms, availability of rigs and related equipment and quality of service, including pipeline connection times and distribution efficiencies affect competition. We believe that our extensive acreage position and our access to gathering and pipeline infrastructure in Pennsylvania, along with our expected activity level and the related services and equipment that we have secured for the upcoming years, enhance our competitive position over other producers who do not have similar systems or services in place.

Major Customers

During the years ended December 31, 2017, 2016 and 2015, two customers accounted for approximately 18% and 11%, two customers accounted for approximately 19% and 10% and two customers accounted for approximately 16% and 14%, respectively, of our total sales. We do not believe that the loss of any of these customers would have a material adverse effect on us because alternative customers are readily available.

Seasonality

Demand for natural gas has historically been seasonal, with peak demand and typically higher prices occurring during the colder winter months.

Regulation of Oil and Natural Gas Exploration and Production

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. This regulation includes requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled in a given field and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. We do not believe, however, we are affected differently by these regulations than others in the industry.

Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of the natural gas we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938 (NGA), the Natural Gas Policy Act of 1978 (NGPA), and the regulations promulgated under those statutes, the Federal Energy Regulatory Commission (FERC) regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Effective beginning in January 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all “first sales” of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC granted to all producers such as us a “blanket certificate of public convenience and necessity” authorizing the sale of natural gas for resale without further FERC approvals. As a result of this policy, all of our produced natural gas is sold at market prices, subject to the terms of any private contracts that may be in effect. In addition, under the provisions of the Energy Policy Act of 2005 (2005 Act), the NGA was amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established regulations intended to increase natural gas pricing transparency by, among other things, requiring market participants to report their gas sales transactions annually to the FERC. The 2005 Act also significantly increased the penalties for violations of the NGA and NGPA and the FERC’s regulations thereunder up to $1,000,000 per day per violation. This maximum penalty authority established by statute has been and will continue to be adjusted periodically for inflation. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties and procedure under its enforcement program.

Some of our pipelines were subject to regulation by the FERC during 2017. Until September 29, 2017, we owned an intrastate natural gas pipeline through our former wholly-owned subsidiary, Cranberry Pipeline Corporation, that provided interstate transportation and storage services pursuant to Section 311 of the NGPA, as well as intrastate transportation and storage services that were regulated by the West Virginia Public Service Commission. We no longer own any interest in Cranberry Pipeline Corporation, and do not operate any natural gas pipelines subject to FERC's jurisdiction.

In 2012, we executed a precedent agreement with Constitution, at the time a wholly owned subsidiary of Williams Partners L.P., for 500,000 Dth per day of pipeline capacity and acquired a 25% equity interest in a pipeline to be constructed in the states of New York and Pennsylvania. On December 2, 2014, the FERC issued a certificate of public convenience and necessity, authorizing the construction and operation of the 124 mile pipeline project that, once completed, will provide 650,000 Dth per day of pipeline capacity. While FERC has issued the certificate, the project scope or timeline for construction and eventual in-service date has been impacted by the public regulatory permitting process. Currently, the in-service date for Constitution cannot be reasonably estimated. If placed into service, the project pipeline will be an interstate pipeline subject to full regulation by FERC under the NGA. See Note 4 of the Notes to the Consolidated Financial Statements for more information about the legal and regulatory actions involving Constitution.

Additionally, in 2014 we executed a precedent agreement with Transcontinental Gas Pipe Line Company, LLC (Transco) for 850,000 Dth per day of pipeline capacity and acquired a 20% equity interest in Meade, which was formed to construct a pipeline with Transco from Susquehanna County, Pennsylvania to an interconnect with Transco's mainline in Lancaster County, Pennsylvania. The proposed pipeline will be an interstate pipeline subject to full regulation by the FERC under the NGA. Transco filed an application for a certificate of public convenience and necessity with the FERC on March 31, 2015. On February 3, 2017, the FERC issued a certificate of public convenience and necessity, authorizing the construction and operation of the pipeline project and the project is under construction, with a current expected in-service date of mid-2018.

Our production and gathering facilities are not subject to jurisdiction of the FERC; however, our natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation because the cost of transporting the natural gas once sold to the consuming market is a factor in the prices we receive. Beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted a series of rulemakings that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, requiring interstate pipeline companies to separate their wholesale gas marketing business from their gas transportation business, and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their natural gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants. Most pipelines have also implemented the large scale divestiture of their natural gas gathering facilities to affiliated or non affiliated companies. Interstate pipelines are required to provide unbundled, open and nondiscriminatory transportation and transportation related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. As a result of FERC requiring natural gas pipeline companies to separate marketing and transportation services, sellers and buyers of natural gas have gained direct access to pipeline transportation services, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, we cannot predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Further, we cannot predict whether the recent trend toward federal deregulation of the natural gas industry will continue or what effect future policies will have on our sale of gas.

Federal Regulation of Swap Transactions

We use derivative financial instruments such as collar, swap and basis swap agreements to attempt to more effectively manage price risk due to the impact of changes in commodity prices on our operating results and cash flows. Following enactment of the Dodd Frank Wall Street Reform and Consumer Protection Act (Dodd Frank Act) in July 2010, the Commodity Futures Trading Commission (CFTC) has promulgated regulations to implement statutory requirements for swap transactions, including certain options. The CFTC regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. In addition, all swap market participants are subject to new reporting and recordkeeping requirements related to their swap transactions. We believe that our use of swaps to hedge against commodity exposure qualifies us as an end user, exempting us from the requirement to centrally clear our swaps. Nevertheless, changes to the swap market as a result of Dodd Frank implementation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Federal Regulation of Petroleum

Our sales of crude oil and NGLs are not regulated and are made at market prices. However, the price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines, which are regulated by the FERC under the Interstate Commerce Act (ICA). FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service and that such service not be unduly discriminatory or preferential.

Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may increase or decrease the cost of transporting crude oil and NGLs by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In December 2015, to implement this required five year re determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 1.23% should be the oil pricing index for the five year period beginning July 1, 2016. The result of indexing is a “ceiling rate” for each rate, which is the maximum at which the pipeline may set its interstate transportation rates. A pipeline may also file cost of service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Rates are subject to challenge by protest when they are filed or changed. For indexed rates, complaints alleging that the rates are unjust and unreasonable may only be pursued if the complainant can show that a substantial change has occurred since the enactment of Energy Policy Act of 1992 in either the economic circumstances of the pipeline or in the nature of the services provided that were a basis for the rate. There is no such limitation on complaints alleging that the pipeline’s rates or terms and conditions of service are unduly discriminatory or preferential. We are unable to predict with certainty the effect upon us of these periodic reviews by the FERC of the pipeline index, or any potential future challenges to pipelines' rates.

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Environmental and Safety Regulations

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Governmental authorities enforce compliance with their regulations through fines, injunctions or both. Government regulations can increase the cost of planning, designing, installing and operating, and can affect the timing of installing and operating, oil and natural gas facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of oil and natural gas production operations. No assurance can be given that significant costs and liabilities will not be incurred. Also, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and natural gas production could result in substantial costs and liabilities to us.

U.S. laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment or otherwise relating to the protection of the environment.

Solid and Hazardous Waste. We currently own or lease, and have in the past owned or leased, numerous properties that were used for the production of oil and natural gas for many years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other wastes may have been disposed of or released on or under the properties currently owned or leased by us. State and federal laws applicable to oil and gas wastes and properties have become stricter over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators) or clean up property contamination (including groundwater contamination by prior owners or operators) or to perform plugging operations to prevent future contamination.

We generate some hazardous wastes that are already subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (EPA) has limited the disposal options for certain hazardous wastes. It is possible that certain wastes currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking by March 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. We could, therefore, be subject to more rigorous and costly disposal requirements in the future than we encounter today.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the “Superfund” law, and comparable state laws and regulations impose liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the current and past owners and operators of a site where the release occurred and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. Under CERCLA, such persons may be subject to joint and several strict 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. CERCLA also authorizes the EPA, and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of business, we have used materials and generated wastes and will continue to use materials and generate wastes that may fall within CERCLA’s definition of hazardous substances. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such substances have been released.

Oil Pollution Act. The Federal Oil Pollution Act of 1990 (OPA) and resulting regulations impose a variety of obligations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. The term “waters of the United States” has been broadly defined to include inland water bodies, including wetlands and intermittent streams. The OPA assigns joint and several strict liability to each responsible party for oil removal costs and a variety of public and private damages. The OPA also imposes ongoing requirements on operators, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe that we substantially comply with the Oil Pollution Act and related federal regulations.

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Endangered Species Act. The Endangered Species Act (ESA) restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA, nor are we aware of any proposed listings that will affect our operations. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Clean Water Act. The Federal Water Pollution Control Act (Clean Water Act) and resulting regulations, which are primarily implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities or to cease hauling wastewaters to facilities owned by others that are the source of water discharges. We believe that we substantially comply with the Clean Water Act and related federal and state regulations.

Clean Air Act. Our operations are subject to the Federal Clean Air Act and comparable local and state laws and regulations to control emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control toxic air pollutants and greenhouse gases might require installation of additional controls. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure to comply strictly with air regulations or permits. Regulatory agencies could also require us to cease construction or operation of certain facilities or to install additional controls on certain facilities that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Some of our producing wells and associated facilities are subject to restrictive air emission limitations and permitting requirements. In 2012, the EPA published final New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) that amended the existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and natural gas production, transmission and distribution facilities. In June 2016, the EPA published a final rule that updates and expands the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In addition, in June 2017, the EPA proposed a two year stay of certain requirements contained in June 2016 rule and in November 2017 issued a notice of data availability in support of the stay proposal and provided a 30-day comment period on the information provided. The EPA also published a final rule in June 2016 concerning aggregation of sources that affects source determinations for air permitting in the oil and gas industry. In October 2015, the EPA adopted a lower national ambient air quality standard for ozone. The revised standard could result in additional areas being designated as ozone non-attainment, which could lead to requirements for additional emissions control equipment and the imposition of more stringent permit requirements on facilities in those areas. EPA anticipates promulgating final area designations under the new ozone standard in the first half of 2018. If we are unable to comply with air pollution regulations or to obtain permits for emissions associated with our operations, we could be required to forego construction, modification or certain operations. These regulations may also increase compliance costs for some facilities we own or operate, and result in administrative, civil and/or criminal penalties for non-compliance. Obtaining permits may delay the development of our oil and natural gas projects, including the construction and operation of facilities.

Safe Drinking Water Act. The Safe Drinking Water Act (SDWA) and comparable local and state provisions restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state’s environmental authority. These regulations may increase the costs of compliance for some facilities.

Hydraulic Fracturing. Many of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and natural gas wells. This technology involves the injection of fluids, usually consisting mostly of water but typically including small amounts of several chemical additives, as well as sand into a well under high pressure in order to create fractures in the formation that allow oil or natural gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal, state and local levels have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and natural gas production activities using hydraulic fracturing techniques which could have an adverse effect on oil and natural gas production activities, including operational delays or increased operating costs in the production of oil and natural gas from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells and increased compliance costs, which could

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increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells. For additional information about hydraulic fracturing and related environmental matters, please read "Risk Factors-Federal and state legislation and regulatory initiatives related to oil and gas development, including hydraulic fracturing, could result in increased costs and operating restrictions or delays" in Item 1A.

Greenhouse Gas. In response to studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to global climate change, the United States Congress has considered, but not enacted, legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and 2050. In addition, many 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. The EPA has also begun to regulate carbon dioxide and other greenhouse gas emissions under existing provisions of the Clean Air Act. This includes regulation of methane emissions from new and modified sources in the oil and gas sector. A 2016 information collection request made to oil and natural gas facilities by EPA in connection with its intention at the time to regulate methane emissions from existing sources was withdrawn in March 2017. If we are unable to recover or pass through a significant portion of our costs related to complying with current and future regulations relating to climate change and GHGs, it could materially affect our operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Future legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy. Please read "Risk Factors-Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and natural gas that we produce" in Item 1A.

OSHA and Other Laws and Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA), and comparable state laws. The OSHA hazard communication standard, the EPA community right to know regulations under the Title III of CERCLA and similar state laws 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 related to workplace exposure to hazardous substances and employee health and safety.

Employees

As of December 31, 2017, we had 308 employees. In addition, we had 160 employees that are employed by our wholly-owned subsidiary, GasSearch Drilling Services Corporation. We recognize that our success is significantly influenced by the relationship we maintain with our employees. Overall, we believe that our relations with our employees are satisfactory. Our employees are not represented by a collective bargaining agreement.

Website Access to Company Reports

We make available free of charge through our website, www.cabotog.com, our annual reports on Form 10 K, quarterly reports on Form 10 Q, current reports on Form 8 K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by us. The public may read and copy materials that we file with the SEC at the SEC's Public Reference Room located at 100 F Street, NE, Washington, DC 20549. Information regarding the operation of the Public Reference Room can be obtained by calling the SEC at 1 800 SEC 0330.

Corporate Governance Matters

Our Corporate Governance Guidelines, Corporate Bylaws, Audit Committee Charter, Compensation Committee Charter, Corporate Governance and Nominations Committee Charter, Code of Business Conduct and Safety and Environmental Affairs Committee Charter are available on our website at www.cabotog.com, under the "Governance" section of "About Cabot." Requests can also be made in writing to Investor Relations at our corporate headquarters at Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas 77024.

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ITEM 1A. RISK FACTORS

Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prices we receive for the natural gas and oil that we sell. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Because our reserves are predominantly natural gas (approximately 96% of equivalent proved reserves), changes in natural gas prices have a more significant impact on our financial results than oil prices. Any substantial or extended decline in future natural gas or crude oil prices would have, a material adverse effect our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments. Furthermore, substantial, extended decreases in natural gas and crude oil prices may cause us to delay or postpone a significant portion of our exploration, development and exploitation projects or may render such projects uneconomic, which may result in significant downward adjustments to our estimated proved reserves and could negatively impact our ability to borrow and cost of capital and our ability to access capital markets, increase our costs under our revolving credit facility, and limit our ability to execute aspects of our business plans. See "Risk Factors-Future natural gas and oil price declines may result in write-downs of the carrying amount of our oil and gas properties, which could materially and adversely affect our results of operations."

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include but are not limited to the following:

- the levels and location of natural gas and oil supply and demand and expectations regarding supply and demand, including the potential long-term impact of an abundance of natural gas from shale (such as that produced from our Marcellus Shale properties) on the global natural gas supply;
- the level of consumer demand for natural gas and oil;
- weather conditions;
- political conditions or hostilities in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability and willingness of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level and quantities of foreign imports;
- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall economic conditions, including the value of the U.S. dollar relative to other major currencies.

These factors and the volatile nature of the energy markets make it impossible to predict the future prices of natural gas and oil. If natural gas and oil prices remain low or continue to decline significantly for a sustained period of time, the lower

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prices may cause us to reduce our planned drilling program or adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including:

- decreases in natural gas and oil prices;
- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- surface access restrictions;
- loss of title or other title related issues;
- lack of available gathering or processing facilities or delays in the construction thereof;
- compliance with, or changes in, governmental requirements and regulation, including with respect to wastewater disposal, discharge of greenhouse gases and fracturing; and
- costs of shortages or delays in the availability of drilling rigs or crews and the delivery of equipment and materials.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate within a particular geographic area may decline. We may be unable to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may be unable to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects and any delays in obtaining such permits.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data.

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Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average index price for the respective commodity, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. The present value of future cash flows are based on $2.33 per Mcf of natural gas, $20.64 per Bbl of NGLs and $49.26 per Bbl of oil as of December 31, 2017. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Future natural gas and oil price declines may result in write-downs of the carrying amount of our oil and gas properties, which could materially and adversely affect our results of operations.

The value of our oil and gas properties depends on prices of natural gas and crude oil. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make material downward adjustments to our estimated proved reserves, and could result in an impairment charge and a corresponding write-down of the carrying amount of our oil and natural gas properties. Because our reserves are predominately natural gas (approximately 96% of equivalent proved reserves), changes in natural gas prices have a more significant impact on our financial results than oil prices.

We evaluate our oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate a property's carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future natural gas and oil prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. In the event that commodity prices decline, there could be a significant revision in the future.

Our producing properties are geographically concentrated in the Marcellus Shale in northeast Pennsylvania, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Marcellus Shale in northeast Pennsylvania. At December 31, 2017, 97% of our proved developed reserves and 94% of our total equivalent production were attributable our properties located in the Marcellus Shale, and we expect that concentration to increase slightly in 2018 as a result of the expected sales of our remaining Texas properties in the first half of 2018. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, state and local political forces and governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other conditions or interruption of the processing or transportation of oil, natural gas or NGLs in the region.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop and produce economically.

Our reserve report estimates that production from our proved developed reserves as of December 31, 2017 will decrease at a rate of 12%, 25%, 18% and 14% during 2018, 2019, 2020 and 2021, respectively. Future development of proved undeveloped and other reserves currently not classified as proved developed producing will impact these rates of decline. Because of higher initial decline rates from newly developed reserves, we consider this pattern fairly typical. Exploration, development and exploitation activities involve numerous risks that may result in, among other things, dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all.

We rely upon access to both our revolving credit facility and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by cash flow from operations or other sources. Future challenges in the global financial system, including the capital markets, may adversely affect our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. Adverse economic and market conditions could adversely affect the collectability of our trade receivables and cause our commodity hedging counterparties to be unable to perform their obligations or to seek bankruptcy protection. Future challenges in the economy could also lead to reduced demand for natural gas which could have a negative impact on our revenues.

Risks associated with our debt and the provisions of our debt agreements could adversely affect our business, financial position and results of operations.

As of December 31, 2017, we had approximately $1.5 billion of debt outstanding and we may incur additional indebtedness in the future. Increases in our level of indebtedness may:

- require us to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;
- limit our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making certain investments, and paying dividends;
- place us at a competitive disadvantage compared to our competitors with lower debt service obligations;
- depending on the levels of our outstanding debt, limit our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes; and
- increase our vulnerability to downturns in our business or the economy, including declines in prices for natural gas and oil.

In addition, the margins we pay under our revolving credit facility depend on our leverage ratio. Accordingly, increases in the amount of our indebtedness without corresponding increases in our consolidated EBITDAX, or decreases in our EBITDAX without a corresponding decrease in our indebtedness, may result in an increase in our interest expense.

Our debt agreements also require compliance with covenants to maintain specified financial ratios. If the price that we receive for our natural gas and oil production deteriorates from current levels or continues for an extended period, it could lead to reduced revenues, cash flow and earnings, which in turn could lead to a default due to lack of covenant compliance. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period. A prolonged period of decreased natural gas and oil prices could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. In order to provide a margin of comfort with regard to these financial covenants, we may seek to reduce our capital expenditures, sell non-strategic assets or opportunistically modify or increase our derivative instruments to the extent permitted under our debt agreements. In addition, we may seek to refinance or restructure all or a portion of our indebtedness. We cannot assure you that we will be able to successfully execute any of these strategies, and such strategies may be unavailable on favorable terms or at all. For more information about our debt agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Financial Condition - Capital Resources and Liquidity."

The borrowing base under our revolving credit facility may be reduced, which could limit us in the future.

The borrowing base under our revolving credit facility is currently $3.2 billion, and lender commitments under our revolving credit facility are $1.7 billion. The borrowing base is redetermined annually under the terms of the revolving credit facility on April 1. In addition, either we or the banks may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations, including any such debt repayment obligations.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2018 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2018 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

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

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, oil spills, greenhouse gas or methane emissions and explosions of natural gas transmission lines, may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

Our ability to sell our natural gas and oil production and/or the prices we receive for our production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. We deliver our natural gas and oil production primarily through gathering systems and pipelines that we do not own. The lack of available capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Third-party systems and facilities may be unavailable due to market conditions or mechanical or other reasons. In addition, at current commodity prices, construction of new pipelines and building of such infrastructure may be slower to build out. To the extent these services are unavailable, we would be unable to realize revenue from wells served by such facilities until suitable arrangements are made to market our production. Our failure to obtain these services on acceptable terms could materially harm our business.

For example, the Marcellus Shale wells we have drilled to date have generally reported very high initial production rates. The amount of natural gas being produced in the area from these new wells, as well as natural gas produced from other existing wells, may exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available. In such event, this could result in wells being shut in or awaiting a pipeline connection or capacity and/or natural gas being sold at much lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations and cash flows.

We are subject to complex laws and regulations, including environmental and safety regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including drilling, permitting and safety laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities, and new laws and regulations or revisions or reinterpretations of existing laws and regulations could further increase these costs. In addition, we may be liable for

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environmental damages caused by previous owners or operators of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. For example, we could be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Acquired properties may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include estimates of recoverable reserves, exploration potential, future natural gas and oil prices, operating costs, production taxes and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of 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.

There may be threatened or contemplated claims against the assets or businesses we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We often assume certain liabilities, and we may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. At times, we acquire interests in properties on an "as is" basis with limited representations and warranties and limited remedies for breaches of such representations and warranties. In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties.

The integration of the properties we may acquire could be difficult, and may divert management's attention away from our existing operations.

The integration of the properties we may acquire could be difficult, and may divert management's attention and financial resources away from our existing operations. These difficulties include:

- the challenge of integrating the acquired properties while carrying on the ongoing operations of our business;
- the inability to retain key employees of the acquired business;
- potential lack of operating experience in a geographic market of the acquired properties; and
- the possibility of faulty assumptions underlying our expectations.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our existing business. If management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- well site blowouts, cratering and explosions;
- equipment failures;
- pipe or cement failures and casing collapses, which can release natural gas, oil, drilling fluids or hydraulic fracturing fluids;
- uncontrolled flows of natural gas, oil or well fluids;
- pipeline ruptures;

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- fires;
- formations with abnormal pressures;
- handling and disposal of materials, including drilling fluids and hydraulic fracturing fluids;
- release of toxic gas;
- buildup of naturally occurring radioactive materials;
- pollution and other environmental risks, including conditions caused by previous owners or operators of our properties; and
- natural disasters.

Any of these events could result in injury or loss of human life, loss of hydrocarbons, significant damage to or destruction of property, environmental pollution, regulatory investigations and penalties, suspension or impairment of our operations and substantial losses to us.

Our utilization of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase these risks. In addition, certain segments of our pipelines will periodically require repair, replacement or maintenance, which may be costly.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance against some, but not all, operating risks and losses. We do not carry business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

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

Other companies operate some of the properties in which we have an interest. As of December 31, 2017, non-operated wells represented approximately 14.7% of our total owned gross wells, or approximately 3.8% of our owned net wells. We have limited ability to influence or control the operation or future development of these non-operated properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the capital, equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe will be increasingly important to attaining success in the industry. These companies may also have a greater ability to continue drilling activities during periods of low natural gas and oil prices and to absorb the burden of current and future governmental regulations and taxation.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use financial derivative instruments to manage price risk associated with our natural gas and crude oil production. While there are many different types of derivatives available, we generally utilize collar, swap and basis swap agreements to manage price risk more effectively.

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The collar arrangements are put and call options used to establish floor and ceiling prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The swap agreements call for payments to, or receipts from, counterparties based on whether the index price for the period is greater or less than the fixed price established for that period when the swap is put in place. These arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production;
- production is less than expected; or
- a counterparty is unable to satisfy its obligations.

The CFTC has promulgated regulations to implement statutory requirements for swap transactions. These regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. While we believe that our use of swap transactions exempt us from certain regulatory requirements, the changes to the swap market due to increased regulation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

We will continue to evaluate the benefit of utilizing derivatives in the future. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A for further discussion concerning our use of derivatives.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, 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 and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Federal and state legislation and regulatory initiatives related to oil and gas development, including hydraulic fracturing, could result in increased costs and operating restrictions or delays.

Most of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of several chemical additives—as well as sand or other proppants into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well.

Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has released permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where EPA is the permitting authority, including Pennsylvania. As a result, we may be subject to additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. In addition, from time to time, legislation has been introduced, but not enacted, in Congress that would provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids. If enacted, this legislation could establish an additional level of regulation and permitting at the federal, state or local levels, and could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. In March 2015, the Department of the Interior's Bureau of Land Management issued a final rule to regulate hydraulic fracturing on public and Indian land; however, these rules were rescinded by rule in December 2017. We voluntarily disclose on a well-by-well basis the chemicals we use in the hydraulic fracturing process at www.fracfocus.org.

In addition, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal, which could have an adverse effect on oil and natural gas production activities, including operational delays or increased operating costs in the production of oil and natural gas from developing shale plays, or could make it more difficult to perform hydraulic fracturing.

On August 16, 2012, the EPA published final rules that establish new air emission control requirements for natural gas and NGL production, processing and transportation activities, including NSPS to address emissions of sulfur dioxide and volatile organic compounds, and NESHAPS to address hazardous air pollutants frequently associated with gas production and processing activities. In June 2016, the EPA published a final rule that updates and expands the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In June 2017, the EPA proposed a two year stay of certain requirements contained in the June 2016 rule and in November 2017 issued a notice of data availability in support of the stay proposal and provided a 30-day comment period on the information provided. A 2016 information collection request made to oil and natural gas facilities by EPA in connection with its intention at the time to regulate methane emissions from existing sources were withdrawn in March 2017. The EPA also published a final rule in June 2016 concerning aggregation of sources that affects source determinations for air permitting in the oil and gas industry.

Compliance with these requirements, especially the new methane regulation, may require modifications to certain of our operations or increase the cost of new or modified facilities, including the installation of new equipment to control emissions at the well site that could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. Similarly, aggregating our oil and gas facilities for permitting could result in more complex, costly, and time consuming air permitting. Particularly in regard to obtaining pre-construction permits, the final aggregation rule could add costs and cause delays in our operations.

In addition to these federal legislative and regulatory proposals, some states in which we operate, such as Pennsylvania and Texas, and certain local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, including requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. For example, the City of Denton, Texas adopted a moratorium on hydraulic fracturing in November 2014, though it was later lifted in 2015, and New York issued a statewide ban on hydraulic fracturing in June 2015. In addition, Pennsylvania's Act 13 of 2012 became law on February 14, 2012 and amended the state's Oil and Gas Act to, among other things, increase civil penalties and strengthen the Pennsylvania Department of Environmental Protection's (PaDEP) authority over the issuance of drilling permits. Although the Pennsylvania Supreme Court struck down portions of Act 13 that made statewide rules on oil and gas preempt local zoning rules, this could lead to additional local restrictions on oil and gas activity in the state.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. 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. For example, in April 2011, PaDEP called on all Marcellus Shale natural gas drilling operators to voluntarily cease by May 19, 2011 delivering wastewater to those centralized treatment facilities that were grandfathered from the application of PaDEP's Total Dissolved Solids regulations. In June 2016, the EPA published final pretreatment standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works. The regulations were developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. In response to these actions, operators including us have begun to rely more on recycling of flowback and produced water from well sites as a preferred alternative to disposal.

A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing practices. For example, the EPA conducted a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released its final report in December 2016. It concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. This study and other studies that may be undertaken by EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and natural gas that we produce.

Climate change, the costs that may be associated with its effects, and the regulation of greenhouse gas (GHG) emissions have the potential to affect our business in many ways, including increasing the costs to provide our products and services, reducing the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks. In addition, legislative and regulatory responses related to GHG emissions and climate change may increase our operating costs. The United States Congress has previously considered legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in GHG emissions. The United States was actively involved in the negotiations at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their nationally determined contributions, which set emissions reduction goals, every five years. The United States signed the Paris Agreement in April 2016. However, on August 4, 2017, the United States formally communicated to the United Nations its intent to withdraw from participation in the Paris Agreement, which entails a four-year process. In response to the announced withdrawal plan, a number of state and local governments in the United States have expressed intentions to take GHG-related actions. Increased public awareness and concern regarding climate change may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

In September 2009, the EPA finalized a mandatory GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions beginning January 1, 2010. The rule applies to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent (CO_2e) emissions per year and to most upstream suppliers of fossil fuels, as well as manufacturers of vehicles and engines. Subsequently, in November 2010, the EPA issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of CO_2e per year. The rule required reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA each year in March under this rule and have submitted our annual reports in compliance with the deadline. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA. However, in June 2014, the U.S. Supreme Court, in UARG v. EPA, limited the application of the GHG permitting requirements under the Prevention of Significant Deterioration and Title V permitting programs to sources that would otherwise need permits based on the emission of conventional pollutants. In October 2015, the EPA finalized rules that added new sources to the scope of the GHG monitoring and reporting requirements. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. Also, in November 2016, the EPA published a final rule adding monitoring methods for detecting leaks from oil and gas equipment and emission factors for leaking equipment to be used to calculate and report GHG emissions resulting from equipment leaks.

Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the passage of any federal or state climate change laws or regulations in the future could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. In addition, warmer winters as a result of global warming could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any

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changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

Terrorist activities and the potential for military and other actions could adversely affect our business.

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 natural gas and oil, all of which could adversely affect the markets for our operations. Acts of terrorism, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Cyber-attacks targeting our systems or the oil and gas industry systems and infrastructure could adversely affect our business.

Our business and the oil and gas industry in general have become increasingly dependent on digital data, computer networks and connected infrastructure. We depend on this technology to record and store financial data, estimate quantities of natural gas and crude oil reserves, analyze and share operating data and communicate internally and externally. Computers control nearly all of the oil and gas distribution systems in the United States, which are necessary to transport our products to market.

A cyber-attack may involve a hacker, a virus, malware, phishing or other actions for the purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. Unauthorized access to our proprietary information could lead to data corruption or communication or operational disruptions. A cyber-attack directed at oil and gas distribution systems could damage those assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for transported products.

We can provide no assurance that we will not suffer such attacks in the future. As cyber-attackers become more sophisticated, we may be required to expend significant additional resources to continue to protect our business or remediate the damage from cyber-attacks. Furthermore, the continuing and evolving threat of cyber-attacks has resulted in increased regulatory focus on prevention. To the extent we face increased regulatory requirements, we may be required to expend significant additional resources to meet such requirements.

Tax law changes could have an adverse effect on our financial position, results of operations, and cash flows.

On December 22, 2017, the U.S. enacted legislation referred to as the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act significantly changes U.S. corporate income tax laws beginning, generally, in 2018. These changes include, among others, (i) a permanent reduction of the U.S. corporate income tax rate from a top marginal rate of 35% to a flat rate of 21%, (ii) elimination of the corporate alternative minimum tax, (iii) immediate deductions for certain new investments instead of deductions for depreciation expense over time, (iv) limitation on the tax deduction for interest expense to 30% of adjusted taxable income, (v) limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks, and (vi) elimination of many business deductions and credits, including the domestic production activities deduction, the deduction for entertainment expenditures, and the deduction for certain executive compensation in excess of $1 million. Refer to Note 10 of the Notes to the Consolidated Financial Statements, "Income Taxes" for additional discussion on the impact of the Tax Act on the Company. In the absence of guidance on various uncertainties and ambiguities in the application of certain provisions of the Tax Act, we will use what we believe are reasonable interpretations and assumptions in applying the Tax Act. Overall, we expect the provisions of the Tax Act to favorably impact the Company's future effective tax rate, after-tax earnings, and cash flows. However, it is possible that the Internal Revenue Service could issue subsequent guidance or take positions on audit that differ from our prior interpretations and assumptions, which could adversely impact our financial position, results of operations, and cash flows.

While the Tax Act maintains many of the tax incentives and deductions that are used by U.S. oil and gas companies, including the percentage depletion allowance for oil and natural gas companies, the ability to fully deduct intangible drilling costs in the year incurred, and the current amortization period of geological and geophysical expenditures for independent producers, the U.S. tax law is always subject to change. Periodically, legislation is proposed to repeal these industry tax incentives and deductions, and/or to impose new industry taxes. In addition, it is uncertain if and to what extent various states will conform to the Tax Act. Further, many states are currently in deficits, and have been enacting laws eliminating or limiting certain deductions, carryforwards, and credits in order to increase tax revenue.

Should the U.S. or the states pass tax legislation limiting any currently allowed tax incentives and deductions, our taxes would increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities in the U.S. Since future changes to federal and state tax legislation are unknown, we cannot know the ultimate impact such changes may have on our business.

Provisions of Delaware law and our bylaws and charter could discourage change in control transactions and prevent stockholders from receiving a premium on their investment.

Our charter authorizes our Board of Directors to set the terms of preferred stock. In addition, Delaware law contains provisions that impose restrictions on business combinations with interested parties. Our bylaws prohibit the calling of a special meeting by our stockholders and place procedural requirements and limitations on stockholder proposals at meetings of stockholders. Because of these provisions of our charter, bylaws and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our Board of Directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our stockholders to benefit from transactions that are opposed by an incumbent Board of Directors.

The personal liability of our directors for monetary damages for breach of their fiduciary duty of care is limited by the Delaware General Corporation Law and by our charter.

The Delaware General Corporation Law allows corporations to limit available relief for the breach of directors' duty of care to equitable remedies such as injunction or rescission. Our charter limits the liability of our directors to the fullest extent permitted by Delaware law. Specifically, our directors will not be personally liable for monetary damages for any breach of their fiduciary duty as a director, except for liability:

- for any breach of their duty of loyalty to the Company or our stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- under provisions relating to unlawful payments of dividends or unlawful stock repurchases or redemptions; and
- for any transaction from which the director derived an improper personal benefit.

This limitation may have the effect of reducing the likelihood of derivative litigation against directors, and may discourage or deter stockholders or management from bringing a lawsuit against directors for breach of their duty of care, even though such an action, if successful, might otherwise have benefited our stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Legal Matters

The information set forth under the heading "Legal Matters" in Note 9 of the Notes to Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

Environmental Matters

From time to time we receive notices of violation from governmental and regulatory authorities in areas in which we operate relating to alleged violations of environmental statutes or the rules and regulations promulgated thereunder. While we cannot predict with certainty whether these notices of violation will result in fines and/or penalties, if fines and/or penalties are imposed, they may result in monetary sanctions, individually or in the aggregate, in excess of $100,000.

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ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 22, 2018 about our executive officers, as such term is defined in Rule 3b-7 of the Securities Exchange Act of 1934, and certain of our other officers.

Name	Age	Position	Officer Since
Dan O. Dinges	64	Chairman, President and Chief Executive Officer	2001
Scott C. Schroeder	55	Executive Vice President and Chief Financial Officer	1997
Jeffrey W. Hutton	62	Senior Vice President, Marketing	1995
Todd L. Liebl	60	Senior Vice President, Land and Business Development	2012
Steven W. Lindeman	57	Senior Vice President, South Region and Engineering	2011
Phillip L. Stalnaker	58	Senior Vice President, North Region	2009
G. Kevin Cunningham	64	Vice President and General Counsel	2010
Charles E. Dyson II	46	Vice President, Information Services	2018
Matthew P. Kerin	37	Vice President and Treasurer	2014
Julius Leitner	55	Vice President, Marketing	2017
Todd M. Roemer	47	Vice President and Controller	2010
Deidre L. Shearer	50	Vice President and Corporate Secretary	2012

All officers are elected annually by our Board of Directors. All of the executive officers have been employed by Cabot Oil & Gas Corporation for at least the last five years, except for Mr. Charles E. Dyson II and Mr. Julius Leitner.

Mr. Dyson joined the Company as the Director of Information Services in October 2015 and was promoted to Vice President of Information Services in February 2018. Prior to joining the Company, he served as the Director of Infrastructure and Support Services at Transocean Offshore Deepwater Drilling, Inc. Mr. Dyson holds a Bachelor of Business Administration degree in Finance from Texas A&M University.

Mr. Leitner joined the Company as Vice President, Marketing in July 2017. Prior to joining the Company, Mr. Leitner held various positions with Shell Energy North America (US) L.P., including Director of Northeast Trading, Director of Producer Services, and Senior Originator, from July 1996 through July 2017. Mr. Leitner holds a Bachelor of Science degree in Biology from Boston College and a Masters of Business Administration from the Mays Business School of Texas A&M University.

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PART II

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

Our common stock is listed and principally traded on the New York Stock Exchange under the ticker symbol "COG." The following table presents the high and low closing sales prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system. Cash dividends paid per share of the common stock are also shown.

	High	Low	Dividends
2017			
First Quarter	$24.10	$20.65	$ 0.02
Second Quarter	$24.99	$21.42	$ 0.05
Third Quarter	$26.91	$24.17	$ 0.05
Fourth Quarter	$29.44	$24.38	$ 0.05
2016			
First Quarter	$22.88	$15.42	$ 0.02
Second Quarter	$25.94	$22.23	$ 0.02
Third Quarter	$26.47	$23.52	$ 0.02
Fourth Quarter	$25.69	$20.03	$ 0.02

As of February 1, 2018, there were 365 registered holders of our common stock.

In January 2018, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.05 per share to $0.06 per share.

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EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2017 regarding the number of shares of common stock that may be issued under our 2014 and 2004 incentive plans.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted-average exercise price of outstanding options, warrants and rights		(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
Equity compensation plans approved by security holders	3,244,739	(1)	$ 17.59	(2)	14,935,363	(3)
Equity compensation plans not approved by security holders	n/a		n/a		n/a	
Total	3,244,739		$ 17.59		14,935,363	

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(1) Includes 57,144 SARs to be settled in common stock, which are fully vested; 1,095,970 employee performance shares, the performance periods of which end on December 31, 2017, 2018 and 2019; 1,109,708 TSR performance shares, the performance periods of which end on December 31, 2017, 2018 and 2019; 574,354 hybrid performance shares, which vest, if at all, in 2018, 2019, and 2020; and 407,563 restricted stock units awarded to the non-employee directors, the restrictions on which lapse upon a non-employee director's departure from the Board of Directors.

(2) Price is only with respect to the 57,144 SARs outstanding because all other outstanding awards are issued without an exercise price.

(3) Includes 161,450 shares of restricted stock, the restrictions on which lapse on various dates in 2018, 2019 and 2020; and 14,773,913 shares that are available for future grants under the 2014 Incentive Plan.

ISSUER PURCHASES OF EQUITY SECURITIES

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. The shares included in the table below were repurchased on the open market and were held as treasury stock as of December 31, 2017.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
October 2017	—	—	—	7,054,074
November 2017	177,900	$ 27.81	177,900	6,876,174
December 2017	1,822,100	$ 27.71	1,822,100	5,054,074
Total	2,000,000		2,000,000	

In February 2018, the Board of Directors authorized an increase of 25.0 million shares to our share repurchase program. After this authorization, the total number of shares available for repurchase is 30.1 million shares.

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PERFORMANCE GRAPH

The following graph compares our common stock performance ("COG") with the performance of the Standard & Poor's 500 Stock Index and the Dow Jones U.S. Exploration & Production Index for the period December 2012 through December 2017. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2012 and that all dividends were reinvested.

	December 31,					
Calculated Values	2012	2013	2014	2015	2016	2017
COG	$100.00	$156.13	$119.54	$71.63	$94.94	$117.02
S&P 500	$100.00	$132.39	$150.51	$152.59	$170.84	$208.14
Dow Jones U.S. Exploration & Production	$100.00	$131.84	$117.64	$89.72	$111.69	$113.14

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

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ITEM 6. SELECTED FINANCIAL DATA

The following table summarizes our selected consolidated financial data for the periods indicated. This information should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7, and the Consolidated Financial Statements and related Notes in Item 8.

	Year Ended December 31,				
(In thousands, except per share amounts)	2017	2016	2015	2014	2013
Statement of Operations Data					
Operating revenues	$1,764,219	$1,155,677	$1,357,150	$2,173,011	$1,746,278
Impairment of oil and gas properties and other assets[(1)]	482,811	435,619	114,875	771,037	—
Earnings (loss) on equity method investments[(2)]	(100,486)	(2,477)	6,415	3,080	1,102
Gain (loss) on sale of assets[(3)]	(11,565)	(1,857)	3,866	17,120	21,351
Income (loss) from operations	(151,260)	(564,945)	(88,914)	106,186	551,582
Net income (loss)[(4)]	100,393	(417,124)	(113,891)	104,468	279,773
Basic earnings (loss) per share	$0.22	$(0.91)	$(0.28)	$0.25	$0.67
Diluted earnings (loss) per share	$0.22	$(0.91)	$(0.28)	$0.25	$0.66
Dividends per common share	$0.17	$0.08	$0.08	$0.08	$0.06

	December 31,				
(In thousands)	2017	2016	2015	2014	2013
Balance Sheet Data					
Properties and equipment, net	$3,072,204	$4,250,125	$4,976,879	$4,925,711	$4,546,227
Total assets[(5)]	4,727,344	5,122,569	5,253,038	5,429,705	4,978,038
Current portion of long-term debt	304,000	—	20,000	—	—
Long-term debt[(5)]	1,217,891	1,520,530	1,996,139	1,743,989	1,143,958
Stockholders' equity	2,523,905	2,567,667	2,009,188	2,142,733	2,204,602

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(1) For discussion of impairment of oil and gas properties and other assets, refer to Note 3 of the Notes to the Consolidated Financial Statements.

(2) Earnings (loss) on equity method investments in 2017 includes an other than temporary impairment of $95.9 million associated with our investment in Constitution. Refer to Note 4 of the Notes to the Consolidated Financial Statements.

(3) Loss on sale of assets in 2017 includes an $11.9 million loss from the sale of certain proved and unproved oil and gas properties located in West Virginia, Virginia and Ohio. Gain on sale of assets in 2014 includes a $19.9 million gain from the sale of certain proved and unproved oil and gas properties located in east Texas. Gain on sale of assets in 2013 includes a $19.4 million gain from the sale of certain proved and unproved oil and gas properties located in the Oklahoma and Texas panhandles, and a $17.5 million loss from the sale of certain proved and unproved oil and gas properties located in Oklahoma, Texas and Kansas and an aggregate net gain of $19.5 million from the sale of various other oil and gas properties during the year.

(4) Net income (loss) includes an income tax benefit of $242.9 million as a result of the remeasurement of our net deferred income tax liabilities based on the new lower corporate income tax rate associated with the Tax Act enacted in December 2017.

(5) Effective January 1, 2016, the Company adopted Accounting Standards Update No. 2015-03 as a change in accounting principle. The Consolidated Balance Sheet as of December 31, 2015, 2014 and 2013 has been retrospectively adjusted to reflect the adoption of this guidance, resulting in a decrease of $8.9 million, $8.0 million, and $3.0 million, respectively, in both total assets and long-term debt related to the debt issuance costs on the Company's senior notes.

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

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K contain additional information that should be referred to when reviewing this material.

OVERVIEW

Financial and Operating Overview

Financial and operating results for the year ended December 31, 2017 compared to the year ended December 31, 2016 are as follows:

- Equivalent production increased 58.2 Bcfe, or 9%, from 627.1 Bcfe, or 1,713.4 Mmcfe per day, in 2016 to 685.3 Bcfe, or 1,877.5 Mmcfe per day, in 2017.
- Natural gas production increased 55.2 Bcf, or 9%, from 600.4 Bcf in 2016 to 655.6 Bcf in 2017, as a result of drilling and completion activities in Pennsylvania.
- Crude oil/condensate/NGL production increased 0.5 Mmbbls, or 11%, from 4.5 Mmbbls in 2016 to 5.0 Mmbbls in 2017, as a result of an increase in drilling activities in south Texas, partially offset by a natural decline in production.
- Average realized natural gas price for 2017 was $2.31 per Mcf, 36% higher than the $1.70 per Mcf price realized in 2016.
- Average realized crude oil price for 2017 was $48.16 per Bbl, 29% higher than the $37.30 per Bbl price realized in 2016.
- Drilled 91 gross wells (82.5 net) with a success rate of 98.9% in 2017 compared to 40 gross wells (38.0 net) with a success rate of 100.0% in 2016.
- Completed 105 gross wells (94.2 net) in 2017 compared to 76 gross wells (76.0 net) in 2016.
- Total capital expenditures were $757.2 million in 2017 compared to $372.5 million in 2016.
- Average rig count during 2017 was approximately 2.0 rigs in the Marcellus Shale, approximately 1.0 rig in the Eagle Ford Shale and approximately 0.4 rigs in other areas, compared to an average rig count in the Marcellus Shale of approximately 1.1 rigs and approximately 0.3 rigs in the Eagle Ford Shale during 2016.
- In September 2017, we received proceeds of $32.7 million primarily related to the divestiture of certain oil and gas properties and related pipeline assets in West Virginia, Virginia and Ohio.
- In December 2017, we recognized an impairment loss of $414.3 million associated with our Eagle Ford shale oil and gas properties in south Texas and an other than temporary impairment of $95.9 million associated with our equity method investment in Constitution.
- In December 2017, we recognized an income tax benefit of $242.9 million as a result of the remeasurement of our net deferred income tax liabilities based on the new lower corporate income tax rate associated with the enactment of the Tax Act.
- During 2017, we repurchased 5.0 million shares of our common stock for a total cost of $123.7 million.
- In May 2017, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.02 per share to $0.05 per share.
- In January 2018, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.05 per share to $0.06 per share.
- In February 2018, the Board of Directors authorized an increase of 25.0 million shares to our share repurchase program.

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by pipeline capacity constraints, inventory storage levels,

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basis differentials, weather conditions and other factors. In addition, our realized prices are further impacted by our hedging activities. As a result, we cannot accurately predict future commodity prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital program, production volumes or revenues. Location differentials have increased in certain regions, such as in the Appalachian region, resulting in further declines in natural gas prices. We expect natural gas and crude oil prices to remain volatile. In addition to production volumes and commodity prices, finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success. For information about the impact of realized commodity prices on our natural gas and crude oil and condensate revenues, refer to "Results of Operations" below. See "Risk Factors—Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business" and "Risk Factors—Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable" in Item 1A.

We account for our derivative instruments on a mark-to-market basis with changes in fair value recognized in operating revenues in the Consolidated Statement of Operations. As a result of these mark-to-market adjustments associated with our derivative instruments, we will experience volatility in our earnings due to commodity price volatility. Refer to “Impact of Derivative Instruments on Operating Revenues” below and Note 6 of the Notes to the Consolidated Financial Statements for more information.

Commodity prices have remained volatile but have improved during 2017 compared to the fourth quarter of 2016. In the event that commodity prices significantly decline, management would test the recoverability of the carrying value of its oil and gas properties and, if necessary, record an impairment charge.

We believe that we are well-positioned to manage the challenges presented in depressed commodity pricing environment, and that we can endure the continued volatility in current and future commodity prices by:

- Continuing to exercise discipline in our capital program with the expectation of funding our capital expenditures with cash on hand, operating cash flows, and if required, borrowings under our revolving credit facility.
- Continuing to optimize our drilling, completion and operational efficiencies, resulting in lower operating costs per unit of production.
- Continuing to manage our balance sheet, which we believe provides sufficient availability under our revolving credit facility and existing cash balances to meet our capital requirements and maintain compliance with our debt covenants.
- Continuing to manage price risk by strategically hedging our natural gas and crude oil production.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2017 were from the sale of natural gas and crude oil production and proceeds from the sale of assets. These cash flows were primarily used to fund our capital expenditures (including contributions to our equity method investments), repurchase of shares of our common stock and payment of dividends. See below for additional discussion and analysis of cash flow.

The borrowing base under the terms of our revolving credit facility is redetermined annually in April. In addition, either we or the banks may request an interim redetermination twice a year or in connection with certain acquisitions or divestitures of oil and gas properties. Effective April 11, 2017, the borrowing base and available commitments were reaffirmed at $3.2 billion and $1.7 billion, respectively. As of December 31, 2017, we had no borrowings outstanding and unused commitments of $1.7 billion under our revolving credit facility.

In December 2017, we entered into an agreement to sell certain of our Eagle Ford Shale assets for $765.0 million and expect to close on the sale in the first quarter of 2018. The lenders under our revolving credit facility have agreed to waive the requirement that the borrowing base be reduced upon closing of the Eagle Ford sale provided that the sale of these assets is considered in our upcoming annual borrowing base redetermination on April 1, 2018.

A decline in commodity prices could result in the future reduction of our borrowing base and related commitments under the revolving credit facility. Unless commodity prices decline significantly from current levels, we do not believe that any such reductions would have a significant impact on our ability to service our debt and fund our drilling program and related operations.

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We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. We believe that, with the existing cash on hand, internally generated cash flow and availability under our revolving credit facility, we have the capacity to finance our spending plans.

At December 31, 2017, we were in compliance with all restrictive financial covenants for both the revolving credit facility and senior notes. As of December 31, 2017, based on our asset coverage and leverage ratios, there were no interest rate adjustments required for our senior notes. See Note 5 of the Notes to the Consolidated Financial Statements for further details regarding our debt.

Cash Flows

Our cash flows from operating activities, investing activities and financing activities are as follows:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Cash flows provided by operating activities	$898,160	$397,441	$749,598
Cash flows used in investing activities	(706,153)	(353,218)	(993,334)
Cash flows provided by (used in) financing activities	(210,502)	453,805	223,296
Net increase (decrease) in cash and cash equivalents	$(18,495)	$498,028	$(20,440)

Operating Activities. Operating cash flow fluctuations are substantially driven by commodity prices, changes in our production volumes and operating expenses. Prices for natural gas and crude oil have historically been volatile, primarily as a result of supply and demand for natural gas and crude oil, pipeline infrastructure constraints, basis differentials, inventory storage levels and seasonal influences. In addition, fluctuations in cash flow may result in an increase or decrease in our capital expenditures. See "Results of Operations" for a review of the impact of prices and volumes on revenues.

Our working capital is substantially influenced by the variables discussed above and fluctuates based on the timing and amount of borrowings and repayments under our revolving credit facility, repayments of debt, the timing of cash collections and payments on our trade accounts receivable and payable, respectively, sales and repurchases of our securities and changes in the fair value of our commodity derivative activity. From time to time, our working capital will reflect a deficit, while at other times it will reflect a surplus. This fluctuation is not unusual. At December 31, 2017 and 2016, we had a working capital surplus of $134.9 million and $458.1 million, respectively. We believe we have adequate liquidity and availability under our revolving credit facility available to meet our working capital requirements over the next twelve months.

Net cash provided by operating activities in 2017 increased by $500.7 million when compared to 2016. This increase was primarily due to higher operating revenues, partially offset by higher operating expenses (excluding non-cash expenses) and unfavorable changes in working capital and other assets and liabilities. The increase in operating revenues was primarily due to an increase in realized natural gas and crude oil prices and higher equivalent production. Average realized natural gas and crude oil prices increased by 36% and 29%, respectively, for 2017 compared to 2016. Equivalent production increased by 9% for 2017 over 2016 as a result of higher natural gas production in the Marcellus Shale.

Net cash provided by operating activities in 2016 decreased by $352.2 million when compared to 2015. This decrease was primarily due to unfavorable changes in working capital and other assets and liabilities and lower operating revenues, partially offset by lower operating expenses (excluding non-cash expenses). The decrease in operating revenues was primarily due to a decrease in realized natural gas and crude oil prices, partially offset by an increase in equivalent production. Average realized natural gas and crude oil prices decreased by 21% and 18%, respectively, for 2016 compared to 2015. Equivalent production increased by 4% for 2016 over 2015 as a result of higher natural gas production in the Marcellus Shale, partially offset by lower crude oil production in the Eagle Ford Shale.

See "Results of Operations" for additional information relative to commodity price, production and operating expense fluctuations. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities.

Investing Activities. Cash flows used in investing activities increased by $352.9 million from 2016 to 2017 due to an increase of $389.4 million in capital expenditures and $28.6 million higher capital contributions associated with our equity method investments, partially offset by $65.0 million higher proceeds from the sale of assets.

Cash flows used in investing activities decreased by $640.1 million from 2015 to 2016 due to a decrease of $580.4 million in capital expenditures, $16.3 million lower acquisition costs and $42.8 million higher proceeds from the sale of assets.

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Financing Activities. Cash flows provided by financing activities decreased by $664.3 million from 2016 to 2017 due to $995.3 million lower net proceeds from the issuance of common stock in 2016, $123.7 million of repurchases of our common stock in 2017 and $42.7 million of higher dividend payments related to an increase in the dividend rate in 2017 and the issuance of common stock in 2016. These decreases were partially offset by $497.0 million of lower net repayments of debt due to the repayment of the outstanding balance on our revolving credit facility and certain of our senior notes with the proceeds from the issuance of common stock in 2016.

Cash flows provided by financing activities increased by $230.5 million from 2015 to 2016 due to $995.3 million of net proceeds related to the issuance of common stock and lower capitalized debt issuance costs of $4.6 million related to the amendment of our revolving credit facility and senior notes in December 2015. These increases were partially offset by $770.0 million of higher net repayments of debt due to the repayment of the outstanding balance on our revolving credit facility and certain of our senior notes with the proceeds from the issuance of common stock and $3.1 million of higher dividend payments.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(Dollars in thousands)	2017	2016
Debt[(1)]	$1,521,891	$1,520,530
Stockholders' equity	2,523,905	2,567,667
Total capitalization	$4,045,796	$4,088,197
Debt to total capitalization	38 %	37 %
Cash and cash equivalents	$480,047	$498,542

(1) Includes $304.0 million of current portion of long-term debt at December 31, 2017. There were no borrowings outstanding under our revolving credit facility as of December 31, 2017 and 2016, respectively.

During 2017, we repurchased 5.0 million shares of our common stock for $123.7 million. During 2017 and 2016, we paid dividends of $78.8 million ($0.17 per share) and $36.2 million ($0.08 per share) on our common stock, respectively. In May 2017, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.02 per share to $0.05 per share.

In January 2018, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.05 per share to $0.06 per share.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital expenditures, excluding any significant property acquisitions, with cash generated from operations and, if required, borrowings under our revolving credit facility. We budget these expenditures based on our projected cash flows for the year.

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The following table presents major components of our capital and exploration expenditures:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Capital expenditures			
Drilling and facilities	$637,207	$359,479	$729,994
Leasehold acquisitions	102,265	2,703	20,097
Property acquisitions	—	—	16,312
Pipeline and gathering	716	1,909	2,373
Other	17,034	8,386	4,739
	757,222	372,477	773,515
Exploration expenditures(1)	21,526	27,662	27,460
Total	$778,748	$400,139	$800,975

(1) Exploration expenditures include $3.8 million, $10.1 million and $3.3 million of exploratory dry hole expenditures in 2017, 2016 and 2015, respectively.

In 2017, we drilled 91 gross wells (82.5 net) and completed 105 gross wells (94.2 net), of which 50 gross wells (44.3 net) were drilled but uncompleted in prior years. In 2018, we plan to allocate the majority of our capital to the Marcellus Shale, where we expect to drill 85 gross wells (85.0 net) and complete 95 gross wells (95.0 net). Our 2018 drilling program includes approximately $890.0 million in total capital expenditures. We will continue to assess the natural gas price environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. A summary of our contractual obligations as of December 31, 2017 are set forth in the following table:

	Payments Due by Year				
(In thousands)	Total	2018	2019 to 2020	2021 to 2022	2023 & Beyond
Debt	$1,528,000	$304,000	$87,000	$188,000	$949,000
Interest on debt(1)	340,278	65,947	100,780	84,002	89,549
Transportation and gathering agreements(2)	1,744,684	105,478	320,671	314,448	1,004,087
Operating leases(2)	30,005	6,541	12,298	6,623	4,543
Equity investment contribution commitments(3)	75,000	60,000	15,000	—	—
Total contractual obligations	$3,717,967	$541,966	$535,749	$593,073	$2,047,179

(1) Interest payments have been calculated utilizing the rates associated with our senior notes outstanding at December 31, 2017, assuming that our senior notes will remain outstanding through their respective maturity dates.

(2) For further information on our obligations under transportation and gathering agreements and operating leases, see Note 9 of the Notes to the Consolidated Financial Statements.

(3) For further information on our equity investment contribution commitments, see Note 4 of the Notes to the Consolidated Financial Statements.

Amounts related to our asset retirement obligation are not included in the above table given the uncertainty regarding the actual timing of such expenditures. The total amount of our asset retirement obligation at December 31, 2017 was $64.3 million, of which $15.7 million was classified as liabilities held for sale. See Note 8 of the Notes to the Consolidated Financial Statements for further details.

We have no off-balance sheet debt or other similar unrecorded obligations.

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Potential Impact of Our Critical Accounting Policies

Our significant accounting policies are described in Note 1 of the Notes to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements, which is in accordance with accounting principles generally accepted in the United States, requires management to make certain estimates and judgments that affect the amounts reported in our financial statements and the related disclosures of assets and liabilities. The following accounting policies are our most critical policies requiring more significant judgments and estimates. We evaluate our estimates and assumptions on a regular basis. Actual results could differ from those estimates.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for our oil and gas producing activities. Acquisition costs for proved and unproved properties are capitalized when incurred. Judgment is required to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of costs incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole costs are expensed. Development costs, including costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations and judgment of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and crude oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Any significant variance in the interpretations or assumptions could materially affect the estimated quantity and value of our reserves and can change substantially over time. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of reservoir performance, drilling activity, commodity prices, fluctuations in operating expenses, technological advances, new geological or geophysical data or other economic factors. Accordingly, reserve estimates are generally different from the quantities ultimately recovered. We cannot predict the amounts or timing of such future revisions.

Our reserves have been prepared by our petroleum engineering staff and audited by Miller and Lents, independent petroleum engineers, who in their opinion determined the estimates presented to be reasonable in the aggregate. For more information regarding reserve estimation, including historical reserve revisions, refer to the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8.

Our rate of recording depreciation, depletion and amortization (DD&A) expense is dependent upon our estimate of proved and proved developed reserves, which are utilized in our unit-of-production calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it uneconomic to drill and produce higher cost fields. A 5% positive or negative revision to proved reserves would result in a decrease of $0.03 per Mcfe and an increase of $0.04 per Mcfe, respectively, on our DD&A rate. Revisions in significant fields may individually affect our DD&A rate. It is estimated that a positive or negative reserve revision of 10% in one of our most productive fields would result in a decrease of $0.04 per Mcfe and an increase of $0.05 per Mcfe, respectively, on our total DD&A rate. These estimated impacts are based on current data, and actual events could require different adjustments to our DD&A rate.

In addition, a decline in proved reserve estimates may impact the outcome of our impairment test under applicable accounting standards. Due to the inherent imprecision of the reserve estimation process, risks associated with the operations of proved producing properties and market sensitive commodity prices utilized in our impairment analysis, management cannot determine if an impairment is reasonably likely to occur in the future.

Carrying Value of Oil and Gas Properties

We evaluate our proved oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future natural gas and crude oil prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process, historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. In the event that commodity prices significantly decline, management would test the recoverability of the carrying value of its oil and gas properties and, if necessary, record an impairment charge. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and oil.

Unproved oil and gas properties are assessed periodically for impairment on an aggregate basis through periodic updates to our undeveloped acreage amortization based on past drilling and exploration experience, our expectation of converting leases to held by production and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. Historically, the average property life in each of the geographical areas has not significantly changed and generally range from three to five years. The commodity price environment may impact the capital available for exploration projects as well as development drilling. We have considered these impacts when determining the amortization rate of our undeveloped acreage, especially in exploratory areas. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately $11.7 million or decrease by approximately $9.6 million, respectively, per year.

As these properties are developed and reserves are proved, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved properties are written off depends on the timing and success of our future exploration and development program.

Asset Retirement Obligations

The majority of our asset retirement obligations (ARO) relates to the plugging and abandonment of oil and gas wells. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. The recognition of an asset retirement obligation requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate. In periods subsequent to initial measurement, the asset retirement cost is depreciated using the units-of-production method, while increases in the discounted ARO liability resulting from the passage of time (accretion expense) are reflected as depreciation, depletion and amortization expense.

Accounting for Derivative Instruments and Hedging Activities

Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each quarterly period, these instruments are marked-to-market. The change in fair value of derivatives not designated as hedges and the ineffective portion of the change in the fair value of derivatives designated as cash flow hedges and are recorded as a component of operating revenues in gain (loss) on derivative instruments in the Consolidated Statement of Operations.

Our derivative contracts are measured based on quotes from our counterparties or internal models. Such quotes and models have been derived using an income approach that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, basis differentials, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term, as applicable. These estimates are derived from or verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness. The determination of fair value also incorporates a credit adjustment for non-performance risk. We measure the non-performance risk of our counterparties by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while our non-performance risk is evaluated using a market credit spread provided by one of our banks.

Our financial condition, results of operations and liquidity can be significantly impacted by changes in the market value of our derivative instruments due to volatility of natural gas and crude oil prices, both NYMEX and basis differentials.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments include the calculation of certain deferred tax assets and liabilities that arise from differences in the timing and recognition of revenue and expenses for tax and financial reporting purposes and estimating reserves for potential adverse outcomes regarding tax positions that we have taken. We account for the uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of

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the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

We believe all of our deferred tax assets, net of any valuation allowances, will ultimately be realized, taking into consideration our forecasted future taxable income, which includes consideration of future operating conditions specifically related to commodity prices. If our estimates and judgments change regarding our ability to realize our deferred tax assets, our tax provision could increase in the period it is determined that it is more likely than not it will not be realized.

Our effective tax rate is subject to variability as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which could affect us. Our effective tax rate is affected by changes in the allocation of property, payroll and revenues among states in which we operate. A small change in our estimated future tax rate could have a material effect on current period earnings.

Contingency Reserves

A provision for contingencies is charged to expense when the loss is probable and the cost is estimable. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. In certain cases, management's judgment is based on the advice and opinions of legal counsel and other advisors, the interpretation of laws and regulations, which can be interpreted differently by regulators and courts of laws, our experience and the experiences of other companies dealing with similar matters, and our decision on how we intend to respond to a particular matter. Actual losses can differ from estimates for various reasons, including those noted above. We monitor known and potential legal, environmental and other contingencies and make our best estimate based on the information we have. Future changes in facts and circumstances not currently foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

Stock-Based Compensation

We account for stock-based compensation under the fair value method of accounting in accordance with applicable accounting standards. Under the fair value method, compensation cost is measured at the grant date for equity-classified awards and remeasured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is generally the vesting period. To calculate fair value, we use either a Monte Carlo or Black-Scholes valuation model, as determined by the specific provisions of the award. The use of these models requires significant judgment with respect to expected life, volatility and other factors. Stock-based compensation cost for all types of awards is included in general and administrative expense in the Consolidated Statement of Operations. See Note 13 of the Notes to the Consolidated Financial Statements for a full discussion of our stock-based compensation.

Recently Adopted Accounting Pronouncements

Refer to Note 1 of the Notes to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for a discussion of recently adopted accounting pronouncements.

Recently Issued Accounting Pronouncements

Refer to Note 1 of the Notes to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for a discussion of new accounting pronouncements that affect us.

OTHER ISSUES AND CONTINGENCIES

Regulations. Our operations are subject to various types of regulation by federal, state and local authorities. See the "Other Business Matters" section of Item 1 for a discussion of these regulations.

Restrictive Covenants. Our ability to incur debt and to make certain types of investments is subject to certain restrictive covenants in our various debt instruments. Among other requirements, our senior note agreements and our revolving credit agreement specify a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of 2.8 to 1.0 and a minimum asset coverage ratio of the present value of proved reserves before income taxes plus adjusted cash to indebtedness and other liabilities of 1.25 to 1.0, which increases to a ratio of 1.75 to 1.0 beginning on January 1, 2018 and thereafter. Our revolving credit agreement also requires us to maintain a minimum current ratio of 1.0 to 1.0. At December 31, 2017, we were in compliance with all restrictive financial covenants in both our senior note agreements and our revolving credit agreement.

Operating Risks and Insurance Coverage. Our business involves a variety of operating risks. See "Risk Factors—We face a variety of hazards and risks that could cause substantial financial losses" in Item 1A. In accordance with customary

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industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. The costs of these insurance policies are somewhat dependent on our historical claims experience, the areas in which we operate and market conditions.

Commodity Pricing and Risk Management Activities. Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and crude oil. Further declines in natural gas and crude oil prices may have a material adverse effect on our financial condition, liquidity, ability to obtain financing and operating results. Lower natural gas and crude oil prices also may reduce the amount of natural gas and crude oil that we can produce economically. Historically, natural gas and crude oil prices have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results. In particular, substantially lower prices would significantly reduce revenue and could potentially trigger an impairment of our oil and gas properties or a violation of certain financial debt covenants. Because our reserves are predominantly natural gas (approximately 96% of equivalent proved reserves), changes in natural gas prices may have a more significant impact on our financial results than oil prices.

The majority of our production is sold at market responsive prices. Generally, if the related commodity index declines, the price that we receive for our production will also decline. Furthermore, we have experienced widening basis differentials in certain regions, such as in the Appalachian region, resulting in further declines in natural gas prices. Therefore, the amount of revenue that we realize is determined by certain factors that are beyond our control. However, management may mitigate this price risk on a portion of our anticipated production with the use of commodity derivatives. Most recently, we have used commodity derivatives such as collar, swap and basis swap arrangements to reduce the impact of sustained lower pricing on our revenue. Under both arrangements, there is also a risk that the movement of index prices may result in our inability to realize the full benefit of an improvement in market conditions.

RESULTS OF OPERATIONS

2017 and 2016 Compared

We reported net income for 2017 of $100.4 million, or $0.22 per share, compared to net loss for 2016 of $417.1 million, or $0.91 per share. The increase in net income was primarily due to higher operating revenues and higher income tax benefit, partially offset by higher operating expenses and loss on sale of assets.

Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
Revenue Variances (In thousands)	2017	2016	Amount	Percent
Natural gas	$1,506,078	$1,022,590	$483,488	47 %
Crude oil and condensate	212,338	151,106	61,232	41 %
Gain (loss) on derivative instruments	16,926	(38,950)	55,876	143 %
Brokered natural gas	17,217	13,569	3,648	27 %
Other	11,660	7,362	4,298	58 %
	$1,764,219	$1,155,677	$608,542	53 %

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	Year Ended December 31,		Variance		Increase (Decrease)
	2017	2016	Amount	Percent	(In thousands)
Price Variances					
Natural gas	$2.30	$1.70	$0.60	35 %	$389,648
Crude oil and condensate	$47.81	$37.65	$10.16	27 %	45,118
Total					$434,766
Volume Variances					
Natural gas (Bcf)	655.6	600.4	55.2	9 %	$93,840
Crude oil and condensate (Mbbl)	4,441	4,013	428	11 %	16,114
Total					$109,954

Natural Gas Revenues

The increase in natural gas revenues of $483.5 million was due to higher natural gas prices and production. The increase in production was a result of an increase in our drilling and completion activities in Pennsylvania.

Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $61.2 million was due to higher production and crude oil prices.

Impact of Derivative Instruments on Operating Revenues

	Year Ended December 31,	
(In thousands)	2017	2016
Cash received (paid) on settlement of derivative instruments		
Gain (loss) on derivative instruments	$8,056	$(1,682)
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	8,870	(37,268)
	$16,926	$(38,950)

Brokered Natural Gas

	Year Ended December 31,		Variance		Price and Volume Variances
	2017	2016	Amount	Percent	(In thousands)
Brokered Natural Gas Sales					
Sales price ($/Mcf)	$3.14	$2.55	$0.59	23 %	$ 3,236
Volume brokered (Mmcf)	x5,485	x5,321	164	3 %	412
Brokered natural gas (In thousands)	$17,217	$13,569			$ 3,648
Brokered Natural Gas Purchases					
Purchase price ($/Mcf)	$2.78	$2.03	$0.75	37 %	$ 4,114
Volume brokered (Mmcf)	x5,485	x5,321	164	3 %	353
Brokered natural gas (In thousands)	$15,252	$10,785			$ 4,467
Brokered natural gas margin (In thousands)	$1,965	$2,784			$ (819)

The $0.8 million decrease in brokered natural gas margin is a result of an increase in purchase price that outpaced the increase in sales price and higher brokered volumes.

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Operating and Other Expenses

(In thousands)	Year Ended December 31, 2017	2016	Variance Amount	Percent
Operating and Other Expenses				
Direct operations	$102,310	$100,696	$1,614	2 %
Transportation and gathering	481,439	436,542	44,897	10 %
Brokered natural gas	15,252	10,785	4,467	41 %
Taxes other than income	33,487	29,223	4,264	15 %
Exploration	21,526	27,662	(6,136)	(22)%
Depreciation, depletion and amortization	568,817	590,128	(21,311)	(4)%
Impairment of oil and gas properties and other assets	482,811	435,619	47,192	11 %
General and administrative	97,786	85,633	12,153	14 %
	$1,803,428	$1,716,288	$87,140	5 %
Earnings (loss) on equity method investments	$(100,486)	$(2,477)	$(98,009)	3,957 %
Loss on sale of assets	(11,565)	(1,857)	(9,708)	523 %
Interest expense, net	82,130	88,336	(6,206)	(7)%
Loss on debt extinguishment	—	4,709	(4,709)	(100)%
Other expense (income)	(4,955)	1,609	6,564	(408)%
Income tax benefit	(328,828)	(242,475)	86,353	(36)%

Total costs and expenses from operations increased by $87.1 million from 2016 to 2017. The primary reasons for this fluctuation are as follows:

- Direct operations increased $1.6 million largely due to an increase in operating costs primarily driven by higher production, partially offset by improved operational efficiencies in 2017 compared to 2016 and the sale of our operations in West Virginia, Virginia and Ohio in the third quarter of 2017.
- Transportation and gathering increased $44.9 million due to higher throughput as a result of higher Marcellus Shale production.
- Brokered natural gas increased $4.5 million from 2016 to 2017. See the preceding table titled "Brokered Natural Gas" for further analysis.
- Taxes other than income increased $4.3 million due to $4.5 million higher production taxes in Texas primarily resulting from higher natural gas and crude oil prices and $2.5 million higher drilling impact fees due to an increase in drilling activity in Pennsylvania. These increases were offset by $2.9 million lower ad valorem taxes as a result of lower property values primarily in south Texas.
- Exploration decreased $6.1 million as a result of a $6.3 million decrease in exploratory dry hole expense and lower charges related to the release of certain drilling rig contracts in south Texas. These decreases were partially offset by an increase of $3.0 million in geological and geophysical costs associated with our new exploratory areas. During 2017, we recorded no rig termination charges, compared to $1.7 million during 2016.
- Depreciation, depletion and amortization decreased $21.3 million, of which $92.8 million was due to a lower DD&A rate of $0.73 per Mcfe for 2017 compared to $0.87 per Mcfe for 2016, partially offset by a $50.6 million increase due to higher equivalent production volumes. The lower DD&A rate was primarily due to lower cost reserve additions and the impairment charge recorded in the second quarter of 2016 associated with higher DD&A rate fields. In addition, amortization of unproved properties increased $27.8 million in 2017 as a result of higher lease acquisition costs and amortization rates.
- Impairment of oil and gas properties and other assets was $482.8 million in 2017 due to the $414.3 million impairment of oil and gas properties located in south Texas and $68.6 million impairment of oil and gas properties and related pipeline assets in West Virginia, Virginia and Ohio. In 2016, we recognized an impairment of oil and gas properties

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and other assets of $435.6 million due to the impairment of oil and gas properties and related pipeline assets in West Virginia and Virginia.

- General and administrative increased $12.2 million due to higher stock-based compensation expense of $8.1 million associated with certain of our market-based performance share awards, $3.8 million higher employee-related expenses and $3.2 million of severance costs for employees terminated as a result of its sale of oil and gas properties located in West Virginia, Virginia and Ohio. These increases were partially offset by $5.5 million lower professional services. The remaining changes were not individually significant.

Earnings (Loss) on Equity Method Investments

The increase in loss on equity method investments is due to an other than temporary impairment of $95.9 million associated with our equity method investment in Constitution and recording our proportionate share of net losses from our equity method investments which increased in 2017 compared to 2016.

Loss on Sale of Assets

Loss on sale of assets increased $9.7 million due to the Company's sale of certain oil and gas properties and related pipeline assets located in West Virginia, Virginia and Ohio. During 2016, we recognized a net aggregate loss of $1.9 million primarily due to the sale of certain of our oil and gas properties in Texas.

Interest Expense, net

Interest expense decreased $6.2 million primarily due to a $1.8 million increase in interest income and a $2.1 million decrease in interest expense resulting from the repayment of the outstanding borrowings under our revolving credit facility in March 2016, which has remained undrawn through December 31, 2017. Interest expense also decreased $2.4 million resulting from the repurchase of $64.0 million of our 6.51% weighted-average senior notes in May 2016 and the repayment of $20.0 million of our 7.33% weighted-average senior notes in July 2016.

Loss on Debt Extinguishment

A $4.7 million debt extinguishment loss was recognized in the second quarter of 2016 related to the premium paid for the repurchase of a portion of our 6.51% weighted-average senior notes in May 2016 and the write-off of a portion of the associated deferred financing costs due to early repayment.

Other Expense (Income)

Other income increased $6.6 million primarily due to a curtailment gain of $4.9 million on postretirement benefits as a result of the termination of approximately 100 employees in West Virginia.

Income Tax Benefit

Income tax benefit increased $86.4 million due to a higher effective tax rate, partially offset by a lower pretax loss. The effective tax rates for 2017 and 2016 were 143.9% and 36.8%, respectively. The increase in the effective tax rate is primarily due to the impact of the tax legislation referred to as the Tax Cuts and Jobs Act (the "Tax Act") that was enacted in December 2017. The Tax Act significantly changes U.S. corporate income tax laws by, among other things, reducing the U.S. corporate income tax rate to 21% starting in 2018. Refer to Note 10 of the Notes to the Consolidated Financial Statements for additional discussion on the impact of the Tax Act on our financial results.

Excluding the impact of any discrete items, the provisions of the Tax Act are expected to reduce our 2018 effective income tax rate to approximately 24.0% to 26.0%. However, this rate may fluctuate based on a number of factors, including but not limited to changes in enacted federal and/or state rates that occur during the year, changes in our executive compensation, the amount of excess tax benefits on stock based compensation, as well as changes in the composition and location of our asset base, our employees and our customers.

2016 and 2015 Compared

We reported a net loss for 2016 of $417.1 million, or $0.91 per share, compared to net loss for 2015 of $113.9 million, or $0.28 per share. The increase in net loss was primarily due to lower operating revenues and higher operating expenses, partially offset by a higher income tax benefit.

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Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
Revenue Variances (In thousands)	2016	2015	Amount	Percent
Natural gas	$1,022,590	$1,025,044	$(2,454)	— %
Crude oil and condensate	151,106	248,211	(97,105)	(39)%
Gain (loss) on derivative instruments	(38,950)	56,686	(95,636)	(169)%
Brokered natural gas	13,569	16,383	(2,814)	(17)%
Other	7,362	10,826	(3,464)	(32)%
	$1,155,677	$1,357,150	$(201,473)	(15)%

	Year Ended December 31,		Variance		Increase (Decrease)
	2016	2015	Amount	Percent	(In thousands)
Price Variances					
Natural gas	$1.70	$1.81	$(0.11)	(6)%	$(64,718)
Crude oil and condensate	$37.65	$45.72	$(8.07)	(18)%	(32,365)
Total					$(97,083)
Volume Variances					
Natural gas (Bcf)	600.4	566.0	34.4	6 %	$62,264
Crude oil and condensate (Mbbl)	4,013	5,429	(1,416)	(26)%	(64,740)
Total					$(2,476)

Natural Gas Revenues

The decrease in natural gas revenues of $2.5 million was due to lower natural gas prices, partially offset by higher production. The increase in production was a result of our drilling and completion activities in Pennsylvania, partially offset by the divestiture of certain oil and gas properties in east Texas in early 2016.

Crude Oil and Condensate Revenues

The decrease in crude oil and condensate revenues of $97.1 million was due to lower production and crude oil prices. The decrease in production was a result of a decrease in drilling and completion activities in south Texas.

Impact of Derivative Instruments on Operating Revenues

	Year Ended December 31,	
(In thousands)	2016	2015
Cash received (paid) on settlement of derivative instruments		
Gain (loss) on derivative instruments	(1,682)	194,289
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	(37,268)	(137,603)
	$(38,950)	$56,686

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Brokered Natural Gas

	Year Ended December 31,		Variance		Price and Volume Variances
	2016	2015	Amount	Percent	(In thousands)
Brokered Natural Gas Sales					
Sales price ($/Mcf)	$2.55	$2.83	$(0.28)	(10)%	$ (1,490)
Volume brokered (Mmcf)	x5,321	x5,784	(463)	(8)%	(1,324)
Brokered natural gas (In thousands)	$13,569	$16,383			$ (2,814)
Brokered Natural Gas Purchases					
Purchase price ($/Mcf)	$2.03	$2.18	$(0.15)	(7)%	$ (798)
Volume brokered (Mmcf)	x5,321	x5,784	(463)	(8)%	(1,009)
Brokered natural gas (In thousands)	$10,785	$12,592			$ (1,807)
Brokered natural gas margin (In thousands)	$2,784	$3,791			$ (1,007)

The $1.0 million decrease in brokered natural gas margin is a result of a decrease in sales price that outpaced the decrease in purchase price and lower brokered volumes.

Operating and Other Expenses

	Year Ended December 31,		Variance	
(In thousands)	2016	2015	Amount	Percent
Operating and Other Expenses				
Direct operations	$100,696	$140,814	$(40,118)	(28)%
Transportation and gathering	436,542	427,588	8,954	2 %
Brokered natural gas	10,785	12,592	(1,807)	(14)%
Taxes other than income	29,223	42,809	(13,586)	(32)%
Exploration	27,662	27,460	202	1 %
Depreciation, depletion and amortization	590,128	622,211	(32,083)	(5)%
Impairment of oil and gas properties and other assets	435,619	114,875	320,744	279 %
General and administrative	85,633	67,996	17,637	26 %
	$1,716,288	$1,456,345	$259,943	18 %
Earnings (loss) on equity method investments	$(2,477)	$6,415	$(8,892)	(139)%
Gain (loss) on sale of assets	(1,857)	3,866	(5,723)	(148)%
Loss on debt extinguishment	4,709	—	4,709	100 %
Interest expense, net	88,336	96,911	(8,575)	(9)%
Other expense (income)	1,609	1,448	161	11 %
Income tax benefit	(242,475)	(73,382)	169,093	230 %

Total costs and expenses from operations increased by $259.9 million from 2015 to 2016. The primary reasons for this fluctuation are as follows:

- Direct operations decreased $40.1 million largely due to improved operational efficiencies, cost reductions from service providers and suppliers in 2016 compared to 2015 and divestiture of certain oil and gas properties in east Texas in February 2016.
- Transportation and gathering increased $9.0 million due to higher throughput as a result of higher Marcellus Shale production and the commencement of various transportation and gathering agreements in the Marcellus Shale throughout 2015.
-

Brokered natural gas decreased $1.8 million from 2015 to 2016. See the preceding table titled “Brokered Natural Gas” for further analysis.

- Taxes other than income decreased $13.6 million due to $7.2 million lower production taxes resulting from lower crude oil prices and production in south Texas and the receipt of a production tax refund of $1.9 million in February 2016. Additionally, drilling impact fees decreased $1.5 million as a result of drilling fewer wells in Pennsylvania during 2016 compared to 2015 and ad valorem taxes decreased $3.8 million as a result of lower property values primarily in south Texas. The remaining changes were not individually significant.
- Exploration increased $0.2 million as a result of a $6.7 million increase in exploratory dry hole expense, partially offset by lower charges related to the release of certain drilling rig contracts in south Texas and $2.7 million lower geophysical and geological costs and other exploration expenses. During 2016, we recorded rig termination charges of $1.7 million, compared to $5.1 million during 2015.
- Depreciation, depletion and amortization decreased $32.1 million, of which $41.2 million was due to a lower DD&A rate of $0.87 per Mcfe for 2016 compared to $0.93 per Mcfe for 2015, partially offset by a $23.0 million increase due to higher equivalent production volumes. The lower DD&A rate was primarily due to lower cost reserve additions and the impairment charge recorded in the fourth quarter of 2015 associated with higher DD&A rate fields. In addition, amortization of unproved properties decreased $16.4 million in 2016 as a result of lower lease acquisition costs and lower amortization rates.
- Impairment of oil and gas properties and other assets was $435.6 million in 2016 due to the impairment of oil and gas properties and related pipeline assets in West Virginia and Virginia. In 2015, we recognized an impairment of oil and gas properties of $114.9 million related to certain fields in south Texas, east Texas and Louisiana. The impairment of these fields was due to a significant decline in commodity prices in late 2015.
- General and administrative increased $17.6 million due to higher stock-based compensation expense of $12.3 million primarily the result of an increase in the Company's stock price during 2016 compared to 2015 and $2.7 million higher professional services. The remaining changes were not individually significant.

Earnings (Loss) on Equity Method Investments

The increase in loss on equity method investments is due to recording our proportionate share of net losses from our equity method investments which increased in 2016 compared to 2015.

Gain (Loss) on Sale of Assets

During 2016, we recognized a net aggregate loss of $1.9 million primarily due to the sale of certain of our oil and gas properties in east and south Texas. During 2015, we recognized a net aggregate gain of $3.9 million primarily due to the sale of certain unproved oil and gas properties in east Texas.

Loss on Debt Extinguishment

A $4.7 million extinguishment loss was recognized in the second quarter of 2016 related to the premium paid for the repurchase of a portion of our 6.51% weighted-average senior notes in May 2016 and the write-off of a portion of the associated deferred financing costs due to early repayment.

Interest Expense, net

Interest expense decreased $8.6 million due to a $5.5 million decrease resulting from the repayment of the outstanding borrowings under our revolving credit facility in March 2016, which remained undrawn through December 31, 2016. Interest expense also decreased $3.4 million resulting from the repurchase of a portion of our 6.51% weighted-average senior notes in May 2016 and the repayment of our 7.33% weighted-average senior notes at maturity. These decreases were offset by a $0.6 million increase in commitment fees as a result of an increase in the unused portion of the commitments under our revolving credit facility.

Income Tax Benefit

Income tax benefit increased $169.1 million due to a higher pretax loss, partially offset by a lower effective tax rate. The effective tax rates for 2016 and 2015 were 36.8% and 39.2%, respectively. The decrease in the effective tax rate is primarily due to the impact of non-recurring discrete items recorded during 2016 compared to 2015.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Our primary market risk is exposure to natural gas and crude oil prices. Realized prices are mainly driven by worldwide prices for crude oil and spot market prices for North American natural gas production. Commodity prices can be volatile and unpredictable.

Derivative Instruments and Risk Management Activities

Our risk management strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets through the use of commodity derivatives. A committee that consists of members of senior management oversees our risk management activities. Our commodity derivatives generally cover a portion of our production and provide only partial price protection by limiting the benefit to us of increases in prices, while protecting us in the event of price declines. Further, if any of our counterparties defaulted, this protection might be limited as we might not receive the full benefit of our commodity derivatives. Please read the discussion below as well as Note 6 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our derivative and risk management activities.

Periodically, we enter into commodity derivatives, including collar, swap and basis swap agreements, to protect against exposure to price declines related to our natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity derivatives other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. All of our derivatives are used for risk management purposes and are not held for trading purposes. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. Under the swap agreements, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

As of December 31, 2017, we had the following outstanding financial commodity derivatives:

			Collars					
			Floor		Ceiling		Basis Swaps	Asset
Type of Contract	Volume	Contract Period	Range	Weighted-Average	Range	Weighted-Average	Weighted-Average	(Liability) (In thousands)
Financial contracts								
Natural gas (Leidy)	17.7 Bcf	Jan. 2018 - Dec. 2018					$ (0.71)	(1,168)
Natural gas (Transco)	21.3 Bcf	Jan. 2018 - Dec. 2019					$ 0.42	1,097
Crude oil (WTI/LLS)	2.9 Mmbbl	Jan. 2018 - Dec. 2018	$—	$ 55.00	$63.35-$63.80	$ 63.62		(6,121)
								$ (6,192)

In January 2018, we entered into the following financial commodity derivative contracts:

Type of Contract	Volume	Contract Period	Swaps Weighted- Average	Basis Swaps Weighted- Average
Financial contracts				
Natural gas (NYMEX)	84.4 Bcf	Feb. 2018 - Dec. 2018	$2.93	
Natural gas (NYMEX)	13.3 Bcf	Feb. 2018 - Oct. 2018	$3.10	
Natural gas (Leidy)	16.2 Bcf	Feb. 2018 - Dec. 2018		$(0.68)

In the above tables, natural gas prices are stated per Mcf and crude oil prices are stated per barrel.

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As of December 31, 2017, we had the following outstanding physical commodity derivatives:

Type of Contract	Volume		Contract Period	Weighted-Average Fixed Price	Asset (Liability) (In thousands)
Physical contracts					
Natural gas purchase	81.2	Bcf	Jan. 2018 - Oct. 2018	$3.70	(12,745)
Natural gas sales	11.7	Bcf	Jan. 2018 - Feb. 2018	$4.71	(9,471)
					$ (22,216)

In the table above, natural gas prices are stated per Mcf.

In January 2018, the Company terminated certain physical purchase contracts prior to their settlement date. The termination did not have a material impact on the Consolidated Financial Statements, as the contracts were previously recognized at fair value.

The amounts set forth in the tables above represent our total unrealized derivative position at December 31, 2017 and exclude the impact of non-performance risk. Non-performance risk is considered in the fair value of our derivative instruments that are recorded in our Consolidated Financial Statements and is primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while our non-performance risk is evaluated using a market credit spread provided by one of our banks.

A significant portion of our expected natural gas and crude oil production for 2018 and beyond is currently unhedged and directly exposed to the volatility in natural gas and crude oil market prices, whether favorable or unfavorable. During 2017, natural gas collars with floor prices of $3.09 per Mcf and ceiling prices ranging from $3.42 to $3.45 per Mcf covered 35.5 Bcf, or 5% of natural gas production at an average price of $3.20 per Mcf. Natural gas swaps covered 51.7 Bcf, or 8%, of natural gas production at a weighted-average price of $3.23 per Mcf. Crude oil collars with floor prices of $50.00 per Bbl and ceiling prices ranging from $56.25 to $56.50 per Bbl covered 1.8 Mmbbl, or 41%, of crude oil production at a weighted-average price of $51.78 per Bbl.

We are exposed to market risk on commodity derivative instruments to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. Our counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. We perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any losses related to non-performance risk of our counterparties and we do not anticipate any material impact on our financial results due to non-performance by third parties. However, we cannot be certain that we will not experience such losses in the future.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future commodity prices. See "Forward-Looking Information" for further details.

Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amount reported in the Consolidated Balance Sheet for cash and cash equivalents approximates fair value due to the short-term maturities of these instruments. Cash and cash equivalents are classified as Level 1 in the fair value hierarchy.

We use available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount we would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our senior notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all senior notes and the revolving credit facility is based on interest rates currently available to us.

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The carrying amount and fair value of debt is as follows:

(In thousands)	December 31, 2017 Carrying Amount	December 31, 2017 Estimated Fair Value	December 31, 2016 Carrying Amount	December 31, 2016 Estimated Fair Value
Long-term debt	$1,521,891	$1,527,624	$1,520,530	$1,463,643
Current maturities	(304,000)	(312,055)	—	—
Long-term debt, excluding current maturities	$1,217,891	$1,215,569	$1,520,530	$1,463,643

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm
To the Board of Directors and Stockholders of Cabot Oil & Gas Corporation:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Cabot Oil & Gas Corporation as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income, stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2018

We have served as the Company's auditor since 1989.

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CABOT OIL & GAS CORPORATION
CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)	December 31, 2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	$480,047	$498,542
Accounts receivable, net	216,004	191,045
Income taxes receivable	56,666	10,298
Inventories	8,006	13,304
Current assets held for sale	1,440	—
Other current assets	2,794	2,692
Total current assets	764,957	715,881
Properties and equipment, net (Successful efforts method)	3,072,204	4,250,125
Equity method investments	86,077	129,524
Assets held for sale	778,855	—
Other assets	25,251	27,039
	$4,727,344	$5,122,569
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$238,045	$168,411
Current portion of long-term debt	304,000	—
Accrued liabilities	27,441	21,492
Interest payable	27,575	27,650
Derivative instruments	30,637	40,259
Current liabilities held for sale	2,352	—
Total current liabilities	630,050	257,812
Long-term debt, net	1,217,891	1,520,530
Deferred income taxes	227,030	579,447
Asset retirement obligations	43,601	131,733
Liabilities held for sale	15,748	—
Postretirement benefits	29,396	36,259
Other liabilities	39,723	29,121
Total liabilities	2,203,439	2,554,902
Commitments and contingencies		
Stockholders' equity		
Common stock:		
Authorized — 960,000,000 shares of $0.10 par value in 2017 and 2016, respectively		
Issued — 475,547,419 shares and 475,042,692 shares in 2017 and 2016, respectively	47,555	47,504
Additional paid-in capital	1,742,419	1,727,310
Retained earnings	1,162,430	1,098,703
Accumulated other comprehensive income	2,077	985
Less treasury stock, at cost:		
14,935,926 shares and 9,892,680 shares in 2017 and 2016, respectively	(430,576)	(306,835)
Total stockholders' equity	2,523,905	2,567,667
	$4,727,344	$5,122,569

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

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
(In thousands, except per share amounts)	2017	2016	2015
OPERATING REVENUES			
Natural gas	$1,506,078	$1,022,590	$1,025,044
Crude oil and condensate	212,338	151,106	248,211
Gain (loss) on derivative instruments	16,926	(38,950)	56,686
Brokered natural gas	17,217	13,569	16,383
Other	11,660	7,362	10,826
	1,764,219	1,155,677	1,357,150
OPERATING EXPENSES			
Direct operations	102,310	100,696	140,814
Transportation and gathering	481,439	436,542	427,588
Brokered natural gas	15,252	10,785	12,592
Taxes other than income	33,487	29,223	42,809
Exploration	21,526	27,662	27,460
Depreciation, depletion and amortization	568,817	590,128	622,211
Impairment of oil and gas properties and other assets	482,811	435,619	114,875
General and administrative	97,786	85,633	67,996
	1,803,428	1,716,288	1,456,345
Earnings (loss) on equity method investments	(100,486)	(2,477)	6,415
Gain (loss) on sale of assets	(11,565)	(1,857)	3,866
LOSS FROM OPERATIONS	(151,260)	(564,945)	(88,914)
Interest expense, net	82,130	88,336	96,911
Loss on debt extinguishment	—	4,709	—
Other expense (income)	(4,955)	1,609	1,448
Loss before income taxes	(228,435)	(659,599)	(187,273)
Income tax benefit	(328,828)	(242,475)	(73,382)
NET INCOME (LOSS)	$100,393	$(417,124)	$(113,891)
Earnings (loss) per share			
Basic	$0.22	$(0.91)	$(0.28)
Diluted	$0.22	$(0.91)	$(0.28)
Weighted-average common shares outstanding			
Basic	463,735	456,847	413,696
Diluted	465,551	456,847	413,696
Dividends per common share	$0.17	$0.08	$0.08

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

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Net income (loss)	$100,393	$(417,124)	$(113,891)
Postretirement benefits:			
Net gain (loss)[1]	(2,634)	1,794	1,786
Prior service credit (cost)[2]	5,449	(514)	—
Amortization of prior service cost[3]	(1,723)	70	—
Total other comprehensive income	1,092	1,350	1,786
Comprehensive income (loss)	$101,485	$(415,774)	$(112,105)

(1) Net of income taxes of $1,544, $(1,052) and $(1,043) for the year ended December 31, 2017, 2016 and 2015, respectively.
(2) Net of income taxes of $(3,194) and $301 for the year ended December 31, 2017 and 2016, respectively.
(3) Net of income taxes of $1,010 and $(41) for the year ended December 31, 2017 and 2016, respectively.

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

CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
(In thousands)	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$100,393	$(417,124)	$(113,891)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	568,817	590,128	622,211
Impairment of oil and gas properties and other assets	482,811	435,619	114,875
Deferred income tax benefit	(321,113)	(230,707)	(72,968)
(Gain) loss on sale of assets	11,565	1,857	(3,866)
Exploratory dry hole cost	3,820	10,120	3,452
(Gain) loss on derivative instruments	(16,926)	38,950	(56,686)
Net cash received (paid) in settlement of derivative instruments	8,056	(1,682)	194,289
(Earnings) loss on equity method investments	100,486	2,477	(6,415)
Amortization of debt issuance costs	4,774	5,083	4,454
Stock-based compensation and other	33,419	25,982	13,645
Changes in assets and liabilities:			
Accounts receivable, net	(25,036)	(71,060)	112,406
Income taxes	(46,368)	(5,975)	(711)
Inventories	1,334	3,044	(3,023)
Other current assets	(104)	(21)	(817)
Accounts payable and accrued liabilities	(2,552)	10,858	(55,217)
Interest payable	(75)	(2,573)	(455)
Other assets and liabilities	(5,141)	2,465	(1,685)
Net cash provided by operating activities	898,160	397,441	749,598
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(764,558)	(375,153)	(955,602)
Acquisitions	—	—	(16,312)
Proceeds from sale of assets	115,444	50,419	7,653
Investment in equity method investments	(57,039)	(28,484)	(29,073)
Net cash used in investing activities	(706,153)	(353,218)	(993,334)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from debt	—	90,000	877,000
Repayments of debt	—	(587,000)	(604,000)
Treasury stock repurchases	(123,741)	—	—
Sale of common stock, net	—	995,279	—
Dividends paid	(78,838)	(36,187)	(33,090)
Tax withholding on vesting of stock awards	(7,973)	(5,064)	(8,861)
Capitalized debt issuance costs	—	(3,223)	(7,838)
Other	50	—	85
Net cash (used in) provided by financing activities	(210,502)	453,805	223,296
Net (decrease) increase in cash and cash equivalents	(18,495)	498,028	(20,440)
Cash and cash equivalents, beginning of period	498,542	514	20,954
Cash and cash equivalents, end of period	$480,047	$498,542	$514

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

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands, except per share amounts)	Common Shares	Common Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance at December 31, 2014	422,915	$42,292	9,893	$(306,835)	$710,432	$ (2,151)	$1,698,995	$2,142,733
Net loss	—	—	—	—	—	—	(113,891)	(113,891)
Exercise of stock appreciation rights	40	4	—	—	(946)	—	—	(942)
Stock amortization and vesting	814	81	—	—	12,511	—	—	12,592
Cash dividends at $0.08 per share	—	—	—	—	—	—	(33,090)	(33,090)
Other comprehensive income	—	—	—	—	—	1,786	—	1,786
Balance at December 31, 2015	423,769	$42,377	9,893	$(306,835)	$721,997	$ (365)	$1,552,014	$2,009,188
Net loss	—	—	—	—	—	—	(417,124)	(417,124)
Issuance of common stock	50,600	5,060	—	—	990,229	—	—	995,289
Exercise of stock appreciation rights	28	3	—	—	(201)	—	—	(198)
Stock amortization and vesting	646	64	—	—	16,867	—	—	16,931
Sale of stock held in rabbi trust	—	—	—	—	544	—	—	544
Stock-based compensation	—	—	—	—	(2,126)	—	—	(2,126)
Cash dividends at $0.08 per share	—	—	—	—	—	—	(36,187)	(36,187)
Other comprehensive income	—	—	—	—	—	1,350	—	1,350
Balance at December 31, 2016	475,043	$47,504	9,893	$(306,835)	$1,727,310	$ 985	$1,098,703	$2,567,667
Net income	—	—	—	—	—	—	100,393	100,393
Exercise of stock appreciation rights	137	14	—	—	(14)	—	—	—
Stock amortization and vesting	367	37	—	—	15,123	—	—	15,160
Purchase of treasury stock	—	—	5,043	(123,741)	—	—	—	(123,741)
Cash dividends at $0.17 per share	—	—	—	—	—	—	(78,838)	(78,838)
Other comprehensive income	—	—	—	—	—	1,092	—	1,092
	—	—	—	—	—	—	42,172	42,172

Cumulative effect from accounting change								
Balance at December 31, 2017	475,547	$47,555	14,936	$(430,576)	$1,742,419	$ 2,077	$1,162,430	$2,523,905

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Nature of Operations

Cabot Oil & Gas Corporation and its subsidiaries (the Company) are engaged in the development, exploitation, exploration, production and marketing of natural gas, oil and NGLs exclusively within the continental United States. The Company's exploration and development activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs.

The Company operates in one segment, natural gas and oil development, exploitation and exploration. The Company's oil and gas properties are managed as a whole rather than through discrete operating segments or business units. Operational information is tracked by geographic area; however, financial performance is assessed as a single enterprise and not on a geographic basis. Allocation of resources is made on a project basis across the Company's entire portfolio without regard to geographic areas.

The consolidated financial statements include the accounts of the Company and its subsidiaries after eliminating all significant intercompany balances and transactions. Certain reclassifications have been made to prior year statements to conform with the current year presentation. These reclassifications have no impact on previously reported stockholders' equity, net income (loss) or cash flows.

Significant Accounting Policies

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with a maturity of three months or less and deposits in money market funds that are readily convertible to cash to be cash equivalents. Cash and cash equivalents were primarily concentrated in four financial institutions at December 31, 2017. The Company periodically assesses the financial condition of its financial institutions and considers any possible credit risk to be minimal.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company determines to be uncollectible based on the specific identification method.

Inventories

Inventories are comprised of tubular goods and well equipment and pipeline imbalances. Tubular goods and well equipment balances are carried at average cost.

Natural gas gathering and pipeline operations normally include imbalance arrangements with the pipeline. The volumes of natural gas due to or from the Company under imbalance arrangements are recorded at actual selling or purchase prices, as the case may be, and are adjusted monthly to market prices.

Equity Method Investments

The Company accounts for its investments in entities over which the Company has significant influence, but not control, using the equity method of accounting. Under the equity method of accounting, the Company increases its investment for contributions made and records its proportionate share of net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. The Company records the activity for its equity method investments on a one month lag. In addition, the Company evaluates its equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other than temporary decline in the value of the investment.

Properties and Equipment

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole drilling costs, are expensed. Development costs, including the costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

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Exploratory drilling costs are capitalized when incurred pending the determination of whether a well has found proved reserves. The determination is based on a process which relies on interpretations of available geologic, geophysical, and engineering data. If a well is determined to be successful, the capitalized drilling costs will be reclassified as part of the cost of the well. If a well is determined to be unsuccessful, the capitalized drilling costs will be charged to exploration expense in the Consolidated Statement of Operations in the period the determination is made. If an exploratory well requires a major capital expenditure before production can begin, the cost of drilling the exploratory well will continue to be carried as an asset pending determination of whether reserves have been found only as long as: (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and (ii) drilling of an additional exploratory well is under way or firmly planned for the near future. If drilling in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well is assumed to be impaired and its costs are charged to exploration expense.

Development costs of proved oil and gas properties, including estimated dismantlement, restoration and abandonment costs and acquisition costs, are depreciated and depleted on a field basis by the units-of-production method using proved developed and proved reserves, respectively. Properties related to gathering and pipeline systems and equipment are depreciated using the straight-line method based on estimated useful lives ranging from 10 to 25 years. Buildings are depreciated on a straight-line basis over 25 to 40 years. Certain other assets are depreciated on a straight-line basis over 3 to 10 years.

Costs of sold or abandoned properties that make up a part of an amortization base (partial field) remain in the amortization base if the units-of-production rate is not significantly affected. If significant, a gain or loss, if any, is recognized and the sold or abandoned properties are retired. A gain or loss, if any, is also recognized when a group of proved properties (entire field) that make up the amortization base has been retired, abandoned or sold.

The Company evaluates its proved oil and gas properties for impairment whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. The Company compares expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on estimates of future natural gas and crude oil prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and oil.

Unproved oil and gas properties are assessed periodically for impairment on an aggregate basis through periodic updates to the Company's undeveloped acreage amortization based on past drilling and exploration experience, the Company's expectation of converting leases to held by production and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. During 2017, 2016 and 2015, amortization associated with the Company's unproved properties was $52.8 million, $25.0 million and $41.4 million, respectively, and is included in depreciation, depletion, and amortization in the Consolidated Statement of Operations.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. The asset retirement costs are depreciated using the units-of-production method. At December 31, 2017, there were no assets legally restricted for purposes of settling asset retirement obligations.

Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Accretion expense is included in depreciation, depletion and amortization expense in the Consolidated Statement of Operations.

Derivative Instruments and Hedging Activities

The Company enters into financial derivative contracts, primarily swaps, collars and basis swaps, to manage its exposure to price fluctuations on a portion of its anticipated future natural gas and crude oil production. The Company’s credit agreement restricts the ability of the Company to enter into commodity derivatives other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company’s risk management policies and where such derivatives do not subject the Company to material speculative risks. All of the Company’s derivatives are used for risk management purposes and are not held for trading purposes. We have elected not to designate our financial derivative instruments as accounting hedges under the accounting guidance.

The Company evaluates all of its physical oil and gas purchase and sale contracts to determine if they meet the definition of a derivative. For contracts that meet the definition of a derivative, the Company may elect the normal purchase normal sale (NPNS) exception provided under the accounting guidance and account for the contract using the accrual method of accounting. Contracts that do not qualify for or for which the Company elects not to apply the NPNS exception are accounted for at fair value.

All derivatives, except for derivatives that qualify for the NPNS exception, are recognized on the balance sheet and are measured at fair value. At the end of each quarterly period, these derivatives are marked to market. As a result, changes in the fair value of derivatives are recognized in operating revenues in gain (loss) on derivative instruments. The resulting cash flows are reported as cash flows from operating activities.

Fair Value of Assets and Liabilities

The Company follows the authoritative accounting guidance for measuring fair value of assets and liabilities in its financial statements. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company is able to classify fair value balances based on the observability of these inputs.

The authoritative guidance for fair value measurements establishes three levels of the fair value hierarchy, defined as follows:

- Level 1: Unadjusted, quoted prices for identical assets or liabilities in active markets.
- Level 2: Quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Significant, unobservable inputs for use when little or no market data exists, requiring a significant degree of judgment.

The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. Depending on the particular asset or liability, input availability can vary depending on factors such as product type, longevity of a product in the market and other particular transaction conditions. In some cases, certain inputs used to measure fair value may be categorized into different levels of the fair value hierarchy. For disclosure purposes under the accounting guidance, the lowest level that contains significant inputs used in the valuation should be chosen.

Revenue Recognition

Natural gas and oil sales result from interests in oil and gas properties owned by the Company. Sales of natural gas and oil are recognized when the product is delivered and title transfers to the purchaser. Payment is generally received one to three months after the sale has occurred.

Producer Gas Imbalances. The Company applies the sales method of accounting for natural gas revenue. Under this method, revenues are recognized based on the actual volume of natural gas sold to purchasers. Natural gas production operations may include joint owners who take more or less than the production volumes entitled to them on certain properties. Production volume is monitored to minimize these natural gas imbalances. Under this method, a natural gas imbalance liability is recorded if the Company's excess takes of natural gas exceed its estimated remaining proved developed reserves for these properties at the actual price realized upon the gas sale. A receivable is recognized only to the extent an imbalance cannot be recouped from the reserves in the underlying properties. The Company’s aggregate imbalance positions at December 31, 2017 and 2016 were not material.

Brokered Natural Gas. Revenues and expenses related to brokered natural gas activity are reported gross as part of operating revenues and operating expenses in accordance with applicable accounting standards. The Company buys and sells natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby the Company and/or the counterparty takes title to the natural gas purchased or sold.

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Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

The Company recognizes accrued interest related to uncertain tax positions in interest expense and accrued penalties related to such positions in general and administrative expense in the Consolidated Statement of Operations.

Stock-Based Compensation

The Company accounts for stock-based compensation under the fair value method of accounting. Under this method, compensation cost is measured at the grant date for equity-classified awards and remeasured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is generally the vesting period. To calculate fair value, the Company uses either a Monte Carlo or Black-Scholes valuation model depending on the specific provisions of the award. Stock-based compensation cost for all types of awards is included in general and administrative expense in the Consolidated Statement of Operations.

Effective January 1, 2017, the Company adopted Accounting Standards Update (ASU) No. 2016-09, Improvements to Employee Share-Based Payment Accounting, which requires the Company to record excess tax benefits and tax deficiencies on stock-based compensation in the income statement upon vesting of the respective awards. Prior to the adoption of ASU 2016-09, excess benefits were recorded in additional paid-in capital in the Consolidated Balance Sheet and tax deficiencies reduced additional paid-in capital to the extent they offset previously recorded tax benefits. As a result of the adoption of ASU 2016-09, excess tax benefits and tax deficiencies are included in cash flows from operating activities.

Cash paid by the Company when directly withholding shares from employee stock-based compensation awards for tax-withholding purposes are classified as financing activities in the Consolidated Statement of Cash Flow.

Refer to Recently Adopted Accounting Pronouncements that follow for further information with respect to the adoption of ASU 2016-09.

Environmental Matters

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. Any insurance recoveries are recorded as assets when received.

Credit and Concentration Risk

Substantially all of the Company's accounts receivable result from the sale of natural gas and oil and joint interest billings to third parties in the oil and gas industry. This concentration of purchasers and joint interest owners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. The Company does not anticipate any material impact on its financial results due to non-performance by the third parties.

During the years ended December 31, 2017, 2016 and 2015, two customers accounted for approximately 18% and 11%, two customers accounted for approximately 19% and 10% and two customers accounted for approximately 16% and 14%, respectively, of the Company's total sales. The Company does not believe that the loss of any of these customers would have a material adverse effect because alternative customers are readily available.

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Use of Estimates
In preparing financial statements, the Company follows accounting principles generally accepted in the United States. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. The most significant estimates pertain to proved natural gas and oil reserves and related cash flow estimates which are used to compute depreciation, depletion and amortization and impairments of proved oil and gas properties. Other significant estimates include natural gas and oil revenues and expenses, fair value of derivative instruments, estimates of expenses related to legal, environmental and other contingencies, asset retirement obligations, postretirement obligations, stock-based compensation and deferred income taxes. Actual results could differ from those estimates.
Recently Adopted Accounting Pronouncements
Stock-Based Compensation. In March 2016, the Financial Accounting Standards Board (FASB) issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting, as an amendment to ASC Topic 718. The areas for simplification in this update involve several aspects of the accounting for share-based payment transactions, including the income tax consequences, forfeitures, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance is effective for interim and annual periods beginning after December 15, 2016. Amendments related to the timing of when excess tax benefits are recognized, minimum statutory withholding requirements, forfeitures, and intrinsic value should be applied using a modified retrospective transition method by means of a cumulative-effect adjustment to equity as of the beginning of the period in which the guidance is adopted. Amendments related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement should be applied retrospectively. Amendments requiring recognition of excess tax benefits and tax deficiencies in the income statement and the practical expedient for estimating expected term should be applied prospectively. An entity may elect to apply the amendments related to the presentation of excess tax benefits on the statement of cash flows using either a prospective transition method or a retrospective transition method. The Company elected to apply this guidance on a prospective basis.
The Company adopted this guidance effective January 1, 2017. The recognition of previously unrecognized windfall tax benefits resulted in a cumulative-effect adjustment of $42.2 million, which increased retained earnings and decreased net deferred tax liabilities by the same amount as of the beginning of 2017. Effective January 1, 2017, cash paid by the Company when directly withholding shares from employee awards for tax-withholding purposes was classified as a financing activity. This change was recognized retrospectively beginning January 1, 2015. Prior periods have been adjusted as follows:

	Net Cash Provided by Operating Activities		Net Cash Provided by Financing Activities	
(In thousands)	As Reported	As Adjusted	As Reported	As Adjusted
Year ended December 31, 2015	$740,737	$749,598	$232,157	$223,296
Year ended December 31, 2016	392,377	397,441	458,869	453,805

The remaining provisions of this amendment did not have a material effect on the Company's financial position, results of operations or cash flows.
Accounting Changes and Error Corrections. In January 2017, the FASB issued ASU No. 2017-03, Accounting Changes and Error Corrections (Topic 250) and Investments - Equity Method and Joint Venture (Topic 323), which states that registrants should consider additional qualitative disclosures if the impact of an issued but not yet adopted ASU is unknown or cannot be reasonably estimated and to include a description of the effect of the accounting policies that the registrant expects to apply, if determined. Transition guidance in certain issued but not yet adopted ASUs, including Leases and Revenue Recognition, was also updated to reflect this amendment. This guidance was effective immediately. The adoption of this guidance impacted the Company’s disclosures but had no effect on its financial position, results of operations or cash flows.

Retirement Benefits. In March 2017, the FASB issued ASU No. 2017-07, Compensation - Retirement Benefits (Topic 715). The amendments in this update require that an employer report the service cost component of postretirement benefits in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The amendments in this update also allow only the service cost component to be eligible for capitalization when applicable. The amendments in this update should be applied retrospectively for the presentation of the service cost component and the other components of net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic benefit cost in assets.

The guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. The Company elected to early adopt this guidance effective January 1, 2017. The reclassification of interest and amortization of prior service cost resulted in an increase in operating income and an increase in other expense (non-operating expense) of $1.6 million and $1.4 million for the years ended December 31, 2016 and 2015, respectively.

Recently Issued Accounting Pronouncements

Financial Instruments. In January 2016, the FASB issued ASU 2016-01, Financial Instruments - Overall, as an amendment to ASC Subtopic 825-10. The amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Among other items, this update will simplify the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. When a qualitative assessment indicates that impairment exists, an entity is required to measure the investment at fair value. This impairment assessment reduces the complexity of the other than temporary impairment guidance that entities follow currently. The guidance is effective for annual periods beginning after December 15, 2018, including interim periods within those annual periods. Early adoption of this amendment is not permitted. The adoption of this guidance will change the methodology that the Company uses to evaluate its equity method investments for impairment. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, results of operation or cash flows.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases, as a new Topic, ASC Topic 842. The new lease guidance supersedes Topic 840. The core principle of the guidance is that a company should recognize the assets and liabilities that arise from leases. This ASU does not apply to leases to explore for or use minerals, oil, natural gas and similar nonregenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. The guidance is effective for interim and annual periods beginning after December 15, 2018. This ASU is to be adopted using a modified retrospective approach. The Company plans to adopt this guidance effective January 1, 2019. To date the Company has determined that right to use assets and related liabilities will increase as a result of the adoption of this guidance; however, the extent to which this increase impacts the financial position, results of operations or cash flows has not yet been determined.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, as a new Topic, ASC Topic 606. The new revenue recognition standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606), which deferred the effective date of ASU No. 2014-09 by one year, making the new standard effective for interim and annual periods beginning after December 15, 2017. This ASU can be adopted either retrospectively or as a cumulative-effect adjustment as of the date of adoption.

Additionally, in March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus agent considerations (reporting revenue gross versus net), which clarifies the implementation guidance on principal versus agent considerations on such matters. In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying performance obligations and licensing, which clarifies guidance related to identifying performance obligations and licensing implementation guidance contained in the new revenue recognition standard. In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-scope improvements and practical expedients, which addresses narrow-scope improvements to the guidance on collectibility, non-cash consideration, and completed contracts at transition. Additionally, the amendments in this update provide a practical expedient for contract modifications at transition and an accounting policy election related to the presentation of sales taxes and other similar taxes collected from customers. In December 2016, the FASB issued ASU No. 2016-20, Technical Corrections and Improvements to Topic

606, Revenue from Contracts with Customers, which clarifies the guidance or corrects unintended application of guidance.

The Company plans to adopt this guidance effective January 1, 2018 using the modified retrospective method applied to contracts that are not completed as of that date. The Company has not identified changes to its revenue recognition policies that would result in a material adjustment to the opening balance of retained earnings on January 1, 2018. The Company has also evaluated its agreements with royalty and nonoperated partners for principal versus agent consideration and determined that there are no changes to its existing policies regarding these transactions. Adopting this guidance will result in increased

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disclosures related to revenue recognition policies and disaggregation of revenue in future disclosures in the Company's Consolidated Financial Statements. As allowed by the practical expedients under Topic 606, the Company does not plan to provide expanded disclosures with respect to the value of unsatisfied performance obligations for contracts with variable consideration or with an original term of one year or less.

Statement of Cash Flows. In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The guidance addresses eight specific cash flow issues for which current GAAP is either unclear or does not include specific guidance. The guidance is effective for annual periods beginning after December 15, 2017 and interim periods within those annual periods. Early adoption is permitted, provided that all of the amendments are adopted in the same period. This ASU must be adopted using a retrospective transition method.

The Company expects to classify distributions it receives from its equity method investees based on the nature of distributions approach in which distributions received are classified on the basis of the nature of the activity that generated the distribution as either a return on investment (cash inflows from operating activities) or a return of investment (cash inflows from investing activities). The Company is not currently receiving any distributions from its equity method investees; however, if material distributions are received in the future, the impact on its cash flows could be material. The Company plans to adopt this guidance effective January 1, 2018. The Company has not identified any changes to the remaining areas of this guidance that upon adoption will have a material effect on its cash flows.

2. Divestitures

The Company recognized an aggregate net gain (loss) on sale of assets of $(11.6) million, $(1.9) million and $3.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

In September 2017, the Company sold certain proved and unproved oil and gas properties and related pipeline assets located in West Virginia, Virginia and Ohio for $41.3 million, and recognized an $11.9 million loss on sale of assets. During the second quarter of 2017, the Company had classified these assets as held for sale and recorded an impairment charge of $68.6 million associated with the proposed sale of these properties.

In February 2016, the Company completed the divestiture of certain proved and unproved oil and gas properties in east Texas for $56.4 million and recognized a $0.5 million gain on sale of assets. The purchase price included a $6.3 million deposit that was received in the fourth quarter of 2015.

3. Properties and Equipment, Net

Properties and equipment, net are comprised of the following:

	December 31,	
(In thousands)	2017	2016
Proved oil and gas properties	$4,932,512	$7,437,604
Unproved oil and gas properties	190,474	260,543
Gathering and pipeline systems	1,569	187,846
Land, building and other equipment	82,670	84,462
	5,207,225	7,970,455
Accumulated depreciation, depletion and amortization	(2,135,021)	(3,720,330)
	$3,072,204	$4,250,125

Assets Held for Sale

On December 11, 2017, the Company entered into an agreement to sell its operated and non-operated Haynesville Shale assets to an undisclosed buyer for $30.0 million, subject to customary purchase price adjustments, and classified these assets as held for sale. The Company expects to close this transaction in the first half of 2018.

On December 19, 2017, the Company entered into an agreement to sell its operated and non-operated Eagle Ford Shale assets to an affiliate of Venado Oil & Gas LLC for $765.0 million, subject to customary closing conditions and purchase price adjustments, and classified these assets as held for sale. The Company expects to close this transaction in the first quarter of 2018.

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Balance sheet data related to the assets held for sale is as follows:

(In thousands)	December 31, 2017
ASSETS	
Inventories	$ 1,440
Properties and equipment, net	778,855
	780,295
LIABILITIES	
Accounts payable	2,352
Asset retirement obligations	15,748
	18,100
Net assets held for sale	$ 762,195

The assets held for sale as of December 31, 2017 do not qualify for discontinued operations as they do not represent a strategic shift that will have a major effect of the Company's operations or financial results.

Impairment of Oil and Gas Properties and Other Assets

In December 2017, the Company recorded an impairment of $414.3 million associated with its Eagle Ford Shale oil and gas properties located in south Texas. The impairment of these properties was due to the anticipated sale of these assets, as demonstrated by the execution of a purchase and sale agreement with a third party on December 19, 2017. These assets were designated as held for sale and were reduced to fair value of approximately $765.6 million.

In June 2017, the Company recorded an impairment of $68.6 million associated with its proposed sale of oil and gas properties and related pipeline assets located in West Virginia, Virginia and Ohio. These assets were designated as held for sale as of June 30, 2017 and were reduced to fair value of approximately $37.9 million.

In December 2016, the Company recorded an impairment of $435.6 million associated with oil and gas properties and related pipeline assets located in West Virginia and Virginia. In the fourth quarter of 2016, although oil and natural gas prices had improved since late 2015, the Company performed an impairment test of its West Virginia and Virginia fields because it had then determined that it was more likely than not that we would dispose of these assets significantly earlier than their remaining expected useful life. As a result of its step one assessment, which was based on a probability weighted assessment that considered the anticipated disposition of these assets earlier than their remaining expected useful life, the Company determined that these assets were impaired which resulted in an impairment charge of $435.6 million. These assets were reduced to fair value of approximately $89.2 million. The fair value of these assets was based on a market approach that considered the preliminary price contained in a draft purchase and sale agreement that was under negotiation with a potential buyer as of December 31, 2016.

In December 2015, the Company recorded an impairment of $114.9 million associated with oil and gas properties in certain fields in south Texas, east Texas and Louisiana. The impairment of these fields was due to a significant decline in commodity prices in late 2015. These fields were reduced to fair value of approximately $89.9 million using discounted future cash flows.

The fair value of the impaired assets in 2017 was determined using a market approach that took into consideration the expected sales price included in the respective purchase and sale agreements the Company executed in June and December 2017. Accordingly, the inputs associated with the fair value of these assets were considered Level 3 in the fair value hierarchy. Refer to Note 1 for a description of fair value hierarchy.

The fair value of the impaired assets in 2016 was determined using a market approach that took into consideration the preliminary purchase price included in a draft purchase and sale agreement that was under negotiation with a potential buyer as of December 31, 2016. Accordingly, the inputs associated with the fair value of these assets were considered Level 3 in the fair value hierarchy. Refer to Note 1 for a description of fair value hierarchy.

The fair value of the impaired properties in 2015 was determined using an income approach that was based on significant inputs that were not observable in the market and are considered to be Level 3 inputs as defined by ASC 820. Refer to Note 1 for a description of fair value hierarchy. Key assumptions included (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates based on the Company's experience with similar properties in which it operates; (iii)

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estimated future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate of 10%.

Capitalized Exploratory Well Costs

The following table reflects the net changes in capitalized exploratory well costs:

(In thousands)	Year Ended December 31, 2017	2016	2015
Balance at beginning of period	$—	$ —	$10,557
Additions to capitalized exploratory well costs pending the determination of proved reserves	19,511	—	—
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	—	—	(10,557)
Capitalized exploratory well costs charged to expense	—	—	—
Balance at end of period	$19,511	$ —	$—

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed:

(In thousands)	December 31, 2017	2016	2015
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$19,511	$ —	$ —
Capitalized exploratory well costs that have been capitalized for a period greater than one year	—	—	—
	$19,511	$ —	$ —

4. Equity Method Investments

The Company has two equity method investments, Constitution Pipeline Company, LLC (Constitution) and Meade Pipeline Co LLC (Meade), which are further described below. Activity related to these equity method investments is as follows:

	Constitution Year Ended December 31,			Meade Year Ended December 31,			Total Year Ended December 31,		
(In thousands)	2017	2016	2015	2017	2016	2015	2017	2016	2015
Balance at beginning of period	$96,850	$90,345	$64,268	$32,674	$13,172	$3,761	$129,524	$103,517	$68,029
Contributions	4,350	8,975	19,625	52,689	19,509	9,448	57,039	28,484	29,073
Earnings (loss) on equity method investments	(100,468)	(2,470)	6,452	(18)	(7)	(37)	(100,486)	(2,477)	6,415
Balance at end of period	$732	$96,850	$90,345	$85,345	$32,674	$13,172	$86,077	$129,524	$103,517

Constitution Pipeline Company, LLC

In April 2012, the Company acquired a 25% equity interest in Constitution, which was formed to develop, construct and operate a 124-mile large diameter pipeline to transport natural gas from northeast Pennsylvania to both the New England and New York markets. Under the terms of the agreement, the Company agreed to invest its proportionate share of costs associated with the development and construction of the pipeline and related facilities, subject to a contribution cap of $250 million.

On April 22, 2016, Constitution announced that the New York State Department of Environmental Conservation (NYSDEC) denied Constitution's application for a Section 401 Water Quality Certification (Certification) for the New York State portion of its proposed 124-mile route. In early 2016, Constitution filed legal actions in the U.S. Court of Appeals for the Second Circuit and the U.S. District Court for the Northern District of New York challenging the legality and appropriateness of the NYSDEC’s decision. On March 16, 2017, the U.S. District Court for the Northern District of New York issued an order

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ruling, without prejudice, that it lacked subject matter jurisdiction to hear Constitution's complaint. On August 18, 2017, the Second Circuit issued a decision denying in part and dismissing in part Constitution's appeal. The Second Circuit determined that it lacked jurisdiction to address Constitution's argument that the NYSDEC waived its ability to issue a Certification by unreasonably delaying action on Constitution's application. Instead, the Second Circuit found that jurisdiction over the waiver issue lies exclusively with the United States Court of Appeals for the District of Columbia Circuit. The Second Circuit, however, rejected Constitution's assertion that the denial of the Certification by the NYSDEC was "arbitrary and capricious" and denied Constitution's complaint in that regard. On October 11, 2017, Constitution filed a petition for a declaratory order requesting the Federal Energy Regulatory Commission (FERC) to find that, by operation of law, the Section 401 Water Quality Certification requirement for the New York State portion of the pipeline project was waived due to the failure of the NYSDEC to act on Constitution's application within a reasonable period of time, as required by the Clean Water Act. On January 11, 2018, the FERC denied Constitution's petition. On January 16, 2018, Constitution petitioned the U.S. Supreme Court to review the judgment of the U.S. Court of Appeals for the Second Circuit, asserting that the Second Circuit's decision conflicts with the decisions of the U.S. Supreme Court and federal Courts of Appeals on an important question of federal law. The U.S. Supreme Court has not yet determined if it will hear the case. On February 12, 2018, Constitution filed a rehearing request with the FERC of its findings that the NYSDEC did not waive the Section 401 Water Quality Certification requirement. The FERC has not yet ruled on the rehearing.

Constitution stated that it remains committed to pursuing the project and that it intends to pursue all available options to challenge the NYSDEC's decision. In light of the current status of the remaining litigation and regulatory challenges, Constitution is unable to reasonably estimate its target in-service date.

The Company evaluated its investment in Constitution for other than temporary impairment (OTTI) as of December 31, 2017. The Company's evaluation considered various factors, including but not limited to prior FERC approval and the related economic viability of the project, the other members' continued commitment to the project and the recent legal and regulatory actions. In light of the recent actions taken by the courts and regulators to uphold the NYDEC's denial of the certification and the Company's estimation of the likelihood of an unfavorable outcome associated with the remaining legal and regulatory challenges, the Company recorded an OTTI of $95.9 million in December 2017, reducing its investment in Constitution to its estimated fair value. Fair value was determined using a market approach. The Company will continue to monitor the carrying value of its investment as required. As of December 31, 2017, the Company's carrying value of its investment in Constitution is less than its proportionate share of Constitution's net assets by $95.9 million. This basis difference is due to the Company's recent impairment recorded in the fourth quarter of 2017 and relates entirely to the pipeline assets of Constitution. The Company expects to amortize this basis difference once the related assets of Constitution are placed in service, which may or may not occur, depending on the outcome of the legal and regulatory process.

At this time, the Company remains committed to funding the project in an amount in proportion to its ownership interest for the duration of the remaining legal and regulatory challenges and if successful, the development and construction of the new pipeline.

Meade Pipeline Co LLC

In February 2014, the Company acquired a 20% equity interest in Meade, which was formed to participate in the development and construction of a 177-mile pipeline (Central Penn Line) that will transport natural gas from Susquehanna County, Pennsylvania to an interconnect with Transcontinental Gas Pipe Line Company, LLC's (Transco) mainline in Lancaster County, Pennsylvania. The new pipeline will be constructed and operated by Transco and will be owned by Transco and Meade in proportion to their respective ownership percentages of approximately 61% and 39%, respectively. Under the terms of the Meade LLC agreement, the Company agreed to invest its proportionate share of Meade's anticipated costs associated with the new pipeline. The Company expects to contribute approximately $75.0 million over the next two years. By order issued on February 3, 2017, the FERC issued Transco a certificate of public convenience and necessity authorizing the construction of the new pipeline. The in-service date for the new pipeline is expected to be mid-2018.

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5. Debt and Credit Agreements

The Company's debt and credit agreements consisted of the following:

	December 31,	
(In thousands)	2017	2016
Total debt		
6.51% weighted-average senior notes [(1)]	$361,000	$361,000
9.78% senior notes [(2)]	67,000	67,000
5.58% weighted-average senior notes	175,000	175,000
3.65% weighted-average senior notes	925,000	925,000
Revolving credit facility	—	—
Unamortized debt issuance costs	(6,109)	(7,470)
	$1,521,891	$1,520,530

(1) Includes $237.0 million of current portion of long-term debt at December 31, 2017.

(2) Includes $67.0 million of current portion of long-term debt at December 31, 2017.

The Company has debt maturities of $304.0 million due in 2018, $87.0 million due in 2020 and $188.0 million due in 2021. In addition, the revolving credit facility matures in 2020. No other tranches of debt are due within the next five years.

At December 31, 2017, the Company was in compliance with all restrictive financial covenants, as amended, for both its revolving credit facility and senior notes.

Senior Notes

The Company has various issuances of senior notes. Interest on each of the senior notes is payable semi-annually. Under the terms of the various senior note agreements, the Company may prepay all or any portion of the notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium.

The Company's agreements (as amended) provide that the Company maintain a minimum asset coverage ratio of 1.25 to 1.0 through and including December 31, 2017 and 1.75 to 1.0 beginning on January 1, 2018 and thereafter. The amended agreements also introduced a leverage ratio covenant, which was defined in the agreement as the ratio of debt to consolidated EBITDAX and provided for potential increases to the original coupon rates ranging from 0 to 125 basis points depending on the asset coverage and leverage ratios at the end of the respective quarterly period, as defined in the note agreements. These covenants and the potential coupon rate increases were to remain in effect until the Company maintained a leverage ratio below 3.0 to 1.0 for two consecutive fiscal quarters ending on or after December 31, 2017, or received an investment grade rating by Standard & Poor's Ratings Services (S&P) or Moody's Investor Service, Inc (Moody's). As of December 31, 2017, the Company had maintained a leverage ratio below 3.0 to 1.0 for two consecutive fiscal quarters and is no longer subject to this financial covenant or potential coupon rate increases. As of December 31, 2017, 2016 and 2015, there were no interest rate adjustments required for the Company's senior notes.

The note agreements also include a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of 2.8 to 1.0, which was unchanged by the amendments. There are also various other covenants and events of default customarily found in such debt instruments.

In conjunction with the execution of the amendments, the Company incurred approximately $1.9 million of debt issuance costs, which were capitalized and are being amortized over the term of the respective amended agreements.

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6.51% Weighted-Average Senior Notes

In July 2008, the Company issued $425.0 million of senior unsecured notes to a group of 41 institutional investors in a private placement. The notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$245,000,000	10 years	July 2018	6.44 %
Tranche 2	$100,000,000	12 years	July 2020	6.54 %
Tranche 3	$80,000,000	15 years	July 2023	6.69 %

In May 2016, the Company repurchased $8.0 million of Tranche 1, $13.0 million of Tranche 2 and $43.0 million of Tranche 3 for a total of $64.0 million for $68.3 million. The Company recognized a $4.7 million extinguishment loss associated with the premium paid and the write-off of a portion of the related deferred financing costs due to early repayment.

9.78% Senior Notes

In December 2008, the Company issued $67.0 million aggregate principal amount of 10 year 9.78% senior unsecured notes to a group of four institutional investors in a private placement.

5.58% Weighted-Average Senior Notes

In December 2010, the Company issued $175.0 million of senior unsecured notes to a group of eight institutional investors in a private placement. The notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$88,000,000	10 years	January 2021	5.42 %
Tranche 2	$25,000,000	12 years	January 2023	5.59 %
Tranche 3	$62,000,000	15 years	January 2026	5.80 %

3.65% Weighted Average Senior Notes

In September 2014, the Company issued $925.0 million of senior unsecured notes to a group of 24 institutional investors in a private placement. The notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$100,000,000	7 years	September 2021	3.24 %
Tranche 2	$575,000,000	10 years	September 2024	3.67 %
Tranche 3	$250,000,000	12 years	September 2026	3.77 %

Revolving Credit Agreement

The Company's revolving credit facility is unsecured. The borrowing base is redetermined annually under the terms of the revolving credit facility on April 1. In addition, either the Company or the banks may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Effective April 11, 2017, the Company’s borrowing base and available commitments were reaffirmed at $3.2 billion and $1.7 billion, respectively. The Company's revolving credit facility matures in April 2020.

In December 2017, the Company entered into an agreement to sell certain of its Eagle Ford Shale assets for $765.0 million and expects to close on the sale in the first quarter of 2018. The lenders under the Company's revolving credit facility have agreed to waive the requirement that the borrowing base be reduced upon closing of the Eagle Ford sale provided that the sale of these assets is considered in the Company’s upcoming annual borrowing base redetermination on April 1, 2018.

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The Company's revolving credit agreement (as amended) provides that the Company maintain a minimum asset coverage ratio of 1.25 to 1.0 through and including December 31, 2017 and 1.75 to 1.0 beginning on January 1, 2018 and thereafter. The amended agreement also introduced a leverage ratio covenant, which was defined in the agreement as the ratio of debt to consolidated EBITDAX and increased the maximum leverage ratio and associated margins. Interest rates under the amended revolving credit facility are based on LIBOR or ABR indications, plus a margin which ranges from 50 to 300 basis points, as defined in the amended agreement. These covenants and the and the associated margin adjustments were to remain in effect until the Company maintained a leverage ratio below 3.0 to 1.0 for two consecutive fiscal quarters ending on or after December 31, 2017, or received an investment grade rating by Standard & Poor's Ratings Services (S&P) or Moody’s Investor Service, Inc (Moody's). As of December 31, 2017, the Company had maintained a leverage ratio below 3.0 to 1.0 for two consecutive fiscal quarters and is no longer subject to this financial covenant and the associated margins reverted back to the pre-amendment levels of 50 to 225 basis points.

The revolving credit facility also contains various other customary covenants that remained unchanged as a result of the amendment, which include the following (with all calculations based on definitions contained in the agreement):

(a) Maintenance of a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

(b) Maintenance of a minimum current ratio of 1.0 to 1.0.

The revolving credit facility also provides for a commitment fee on the unused available balance at annual rates ranging from 0.30% to 0.50%. The other terms and conditions of the amended facility are generally consistent with the terms and conditions of the revolving credit facility prior to its amendment.

At December 31, 2017, the Company had no borrowings outstanding under its revolving credit facility and had unused commitments of $1.7 billion. The Company's weighted-average effective interest rates for the revolving credit facility during the years ended December 31, 2016 and 2015 were approximately 2.3% and 2.2%, respectively.

6. Derivative Instruments and Hedging Activities

As of December 31, 2017, the Company had the following outstanding financial commodity derivatives:

			Collars				
			Floor		Ceiling		Basis Swaps
Type of Contract	Volume	Contract Period	Range	Weighted-Average	Range	Weighted-Average	Weighted-Average
Financial contracts							
Natural gas (Leidy)	17.7 Bcf	Jan. 2018 - Dec. 2018					$ (0.71)
Natural gas (Transco)	21.3 Bcf	Jan. 2018 - Dec. 2019					$ 0.42
Crude oil (WTI/LLS)	2.9 Mmbbl	Jan. 2018 - Dec. 2018	$—	$ 55.00	$63.35-$63.80	$ 63.62	

In January 2018, we entered into the following financial commodity derivatives:

			Swaps	Basis Swaps
Type of Contract	Volume	Contract Period	Weighted- Average	Weighted- Average
Financial contracts				
Natural gas (NYMEX)	84.4 Bcf	Feb. 2018 - Dec. 2018	$2.93	
Natural gas (NYMEX)	13.3 Bcf	Feb. 2018 - Oct. 2018	$3.10	
Natural gas (Leidy)	16.2 Bcf	Feb. 2018 - Dec. 2018		$(0.68)

In the tables above, natural gas prices are stated per Mcf and crude oil prices are stated per barrel.

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As of December 31, 2017, the Company had the following outstanding physical commodity derivatives:

Type of Contract	Volume		Contract Period	Weighted-Average Fixed Price
Physical contracts				
Natural gas purchase	81.2	Bcf	Jan. 2018 - Oct. 2018	$3.70
Natural gas sales	11.7	Bcf	Jan. 2018 - Feb. 2018	$4.71

In the table above, natural gas prices are stated per Mcf.

In January 2018, the Company terminated certain physical purchase contracts prior to their settlement date. The termination did not have a material impact on the Consolidated Financial Statements, as the contracts were previously recognized at fair value.

Effect of Derivative Instruments on the Consolidated Balance Sheet

		Fair Values of Derivative Instruments			
		Derivative Assets		Derivative Liabilities	
		December 31,		December 31,	
(In thousands)	Balance Sheet Location	2017	2016	2017	2016
Commodity contracts	Other assets (non-current)	$2,239	$2,991	$—	$—
Commodity contracts	Derivative instruments (current)	—	—	30,637	40,259
		$2,239	$2,991	$30,637	$40,259

Offsetting of Derivative Assets and Liabilities in the Consolidated Balance Sheet

	December 31,	
(In thousands)	2017	2016
Derivative assets		
Gross amounts of recognized assets	$2,239	$2,991
Gross amounts offset in the statement of financial position	—	—
Net amounts of assets presented in the statement of financial position	2,239	2,991
Gross amounts of financial instruments not offset in the statement of financial position	—	—
Net amount	$2,239	$2,991
Derivative liabilities		
Gross amounts of recognized liabilities	$30,637	$40,259
Gross amounts offset in the statement of financial position	—	—
Net amounts of liabilities presented in the statement of financial position	30,637	40,259
Gross amounts of financial instruments not offset in the statement of financial position	241	757
Net amount	$30,878	$41,016

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Effect of Derivative Instruments on the Consolidated Statement of Operations

(In thousands)	Year Ended December 31, 2017	2016	2015
Cash received (paid) on settlement of derivative instruments			
Gain (loss) on derivative instruments	$8,056	$(1,682)	$194,289
Non-cash gain (loss) on derivative instruments			
Gain (loss) on derivative instruments	8,870	(37,268)	(137,603)
	$16,926	$(38,950)	$56,686

Additional Disclosures about Derivative Instruments and Hedging Activities

The use of derivative instruments involves the risk that the counterparties will be unable to meet their obligations under the agreements. The Company's counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and its derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty. The Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. Certain counterparties to the Company's derivative instruments are also lenders under its revolving credit facility. The Company's revolving credit facility and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of its derivative liabilities in certain situations. The Company also has netting arrangements with each of its counterparties that allow it to offset assets and liabilities from separate derivative contracts with that counterparty.

7. Fair Value Measurements

Financial Assets and Liabilities

The following fair value hierarchy table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
Assets				
Deferred compensation plan	$14,966	$ —	$ —	$ 14,966
Derivative instruments	—	—	2,239	2,239
Total assets	$14,966	$ —	$ 2,239	$ 17,205
Liabilities				
Deferred compensation plan	$29,145	$ —	$ —	$ 29,145
Derivative instruments	—	—	30,637	30,637
Total liabilities	$29,145	$ —	$ 30,637	$ 59,782

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2016
Assets				
Deferred compensation plan	$ 12,587	$ —	$ —	$ 12,587
Derivative instruments	—	—	2,991	2,991
Total assets	$ 12,587	$ —	$ 2,991	$ 15,578
Liabilities				
Deferred compensation plan	$ 24,169	$ —	$ —	$ 24,169
Derivative instruments	—	21,400	18,859	40,259
Total liabilities	$ 24,169	$ 21,400	$ 18,859	$ 64,428

The Company's investments associated with its deferred compensation plan consist of mutual funds and deferred shares of the Company's common stock that are publicly traded and for which market prices are readily available.
The derivative instruments were measured based on quotes from the Company's counterparties or internal models. Such quotes and models have been derived using an income approach that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, basis differentials, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. Estimates are derived from or verified using relevant NYMEX futures contracts and/or are compared to multiple quotes obtained from counterparties for reasonableness. The determination of the fair values presented above also incorporates a credit adjustment for non-performance risk. The Company measured the non-performance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions with which it has derivative transactions while non-performance risk of the Company is evaluated using a market credit spread provided by the Company's bank. The Company has not incurred any losses related to non-performance risk of its counterparties and does not anticipate any material impact on its financial results due to non-performance by third parties.
The most significant unobservable inputs relative to the Company's Level 3 derivative contracts are basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties' valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.
The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Balance at beginning of period	$ (15,868)	$ —	$ 85,958
Total gain (loss) included in earnings	(1,866)	(17,886)	32,864
Settlement (gain) loss	(10,664)	2,018	(118,822)
Balance at end of period	$ (28,398)	$ (15,868)	$ —
Change in unrealized gains (losses) relating to assets and liabilities still held at the end of the period	$ (28,398)	$ (15,868)	$ —

There were no transfers between Level 1 and Level 2 fair value measurements for the years ended December 31, 2017, 2016 and 2015.

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Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments of oil and gas properties or other than temporary impairments of equity method investments, at fair value on a nonrecurring basis. The Company recorded an impairment charge related to certain oil and gas properties and other assets during the years ended December 31, 2017, 2016 and 2015. The Company also recorded an other than temporary impairment of its equity method investment in Constitution during the year ended December 31, 2017. Refer to Notes 3 and 4 for additional disclosures related to fair value associated with the impaired assets. As none of the Company's other non-financial assets and liabilities were measured at fair value as of December 31, 2017, 2016 and 2015, additional disclosures were not required.

The estimated fair value of the Company's asset retirement obligation at inception is determined by utilizing the income approach by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the measurement of the asset retirement obligations was classified as Level 3 in the fair value hierarchy.

Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amount reported in the Consolidated Balance Sheet for cash and cash equivalents approximates fair value due to the short-term maturities of these instruments. Cash and cash equivalents are classified as Level 1 in the fair value hierarchy and the remaining financial instruments are classified as Level 2.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's senior notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all senior notes and the revolving credit facility is based on interest rates currently available to the Company. The Company's debt is valued using an income approach and classified as Level 3 in the fair value hierarchy.

The carrying amount and fair value of debt is as follows:

(In thousands)	December 31, 2017		December 31, 2016	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$1,521,891	$1,527,624	$1,520,530	$1,463,643
Current maturities	(304,000)	(312,055)	—	—
Long-term debt, excluding current maturities	$1,217,891	$1,215,569	$1,520,530	$1,463,643

8. Asset Retirement Obligations

Activity related to the Company's asset retirement obligations is as follows:

(In thousands)	Year Ended December 31, 2017
Balance at beginning of period (1)	$133,733
Liabilities incurred	4,653
Liabilities settled	(1,293)
Liabilities divested	(77,965)
Liabilities transferred to liabilities held for sale	(15,748)
Accretion expense	5,173
Balance at end of period (2)	$48,553

(1) Includes $2.0 million of current asset retirement obligations included in accrued liabilities at December 31, 2016.

(2) Includes $5.0 million of current asset retirement obligations included in accrued liabilities at December 31, 2017.

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9. Commitments and Contingencies

Transportation and Gathering Agreements

The Company has entered into certain natural gas and oil transportation and gathering agreements with various pipeline carriers. Under certain of these agreements, the Company is obligated to ship minimum daily quantities, or pay for any deficiencies at a specified rate. The Company's forecasted production to be shipped on these pipelines is expected to exceed minimum daily quantities provided in the agreements. The Company is also obligated under certain of these arrangements to pay a demand charge for firm capacity rights on pipeline systems regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability.

As of December 31, 2017, the Company's future minimum obligations under transportation and gathering agreements are as follows:

(In thousands)	
2018	$105,478
2019	163,017
2020	157,654
2021	157,224
2022	157,224
Thereafter	1,004,087
	$1,744,684

Lease Commitments

The Company leases certain office space, warehouse facilities, vehicles, machinery and equipment under cancelable and non-cancelable leases. Rent expense under these arrangements totaled $9.7 million, $10.7 million and $13.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2017 are as follows:

(In thousands)	
2018	$6,541
2019	6,308
2020	5,990
2021	4,903
2022	1,720
Thereafter	4,543
	$30,005

Legal Matters

The Company is a defendant in various legal proceedings arising in the normal course of business. All known liabilities are accrued when management determines they are probable based on its best estimate of the potential loss. While the outcome and impact of these legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material effect on the Company's financial position, results of operations or cash flows.

Contingency Reserves

When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional losses with respect to those matters in which reserves have been established. The Company believes that any such amount above the amounts accrued would not be material to the Consolidated Financial Statements. Future changes in facts and circumstances not currently foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

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10. Income Taxes

On December 22, 2017, the U.S. enacted tax legislation referred to as the Tax Cuts and Jobs Act (the "Tax Act") which significantly changes U.S. corporate income tax laws beginning, generally, in 2018. These changes include, among others, (i) a permanent reduction of the U.S. corporate income tax rate from a top marginal rate of 35% to a flat rate of 21%, (ii) elimination of the corporate alternative minimum tax, (iii) immediate deductions for certain new investments instead of deductions for depreciation expense over time, (iv) limitation on the tax deduction for interest expense to 30% of adjusted taxable income, (v) limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks, and (vi) elimination of many business deductions and credits, including the domestic production activities deduction, the deduction for entertainment expenditures, and the deduction for certain executive compensation in excess of $1 million. Overall, the Company expects the provisions of the Tax Act to favorably impact its future effective tax rate, after-tax earnings, and cash flows.

Income tax benefit is summarized as follows:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Current			
Federal	$(9,531)	$(9,920)	$983
State	1,816	(1,848)	(1,397)
	(7,715)	(11,768)	(414)
Deferred			
Federal	(313,938)	(218,357)	(72,869)
State	(7,175)	(12,350)	(99)
	(321,113)	(230,707)	(72,968)
Income tax benefit	$(328,828)	$(242,475)	$(73,382)

Income tax benefit was different than the amounts computed by applying the statutory federal income tax rate as follows:

	Year Ended December 31,					
	2017		2016		2015	
(In thousands, except rates)	Amount	Rate	Amount	Rate	Amount	Rate
Computed "expected" federal income tax	$(79,952)	35.00 %	$(230,860)	35.00 %	$(65,546)	35.00 %
State income tax, net of federal income tax benefit	(4,239)	1.86 %	(10,888)	1.65 %	(3,152)	1.68 %
Deferred tax adjustment related to change in overall state tax rate	(48)	0.02 %	(663)	0.10 %	2,822	(1.51)%
Valuation allowance	(505)	0.22 %	221	(0.03)%	187	(0.10)%
Provision to return adjustments	(3,242)	1.42 %	(121)	0.02 %	(6,326)	3.38 %
Excess stock compensation	2,965	(1.30)%	—	— %	—	— %
Tax Act	(242,875)	106.32 %	—	— %	—	— %
Other, net	(932)	0.41 %	(164)	0.02 %	(1,367)	0.73 %
Income tax benefit	$(328,828)	143.95 %	$(242,475)	36.76 %	$(73,382)	39.18 %

In 2017, the Company's overall effective tax rate significantly increased compared to 2016, primarily due to the Tax Act. As a result of the enactment of the Tax Act, we recorded an income tax benefit in December 2017 of $242.9 million resulting from the remeasurement of our net deferred tax liabilities based on the new lower corporate income tax rate. Although the $242.9 million tax benefit represents what we believe is a reasonable estimate of the impact of the income tax effects of the Tax Act on our Consolidated Financial Statements as of December 31, 2017, it should be considered provisional. Once we finalize certain positions when we file our 2017 tax returns, we will be able to conclude whether any further adjustments are required to our net deferred tax liability balance. Any adjustments to this provisional amount will be reported in the period in which any such adjustments are determined.

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Excluding the impact of the Tax Act, the effective tax rate for 2017 was 37.6%. The effective tax rate was higher in 2015 than in 2016 and 2017 (excluding the impact of the Tax Act), primarily due to larger provision-to-return adjustments in 2015 compared to 2016 and 2017.

The composition of net deferred tax liabilities is as follows:

	December 31,	
(In thousands)	2017	2016
Deferred Tax Assets		
Net operating losses	$207,633	$352,001
Alternative minimum tax credits	208,624	218,773
Foreign tax credits	3,541	3,816
Other business credits	3,524	—
Derivative instruments	6,645	13,771
Incentive compensation	15,898	22,852
Deferred compensation	6,065	8,217
Post-retirement benefits	7,265	13,865
Equity method investments	21,812	—
Other	492	2,743
Less: valuation allowance	(16,711)	(5,186)
Total	464,788	630,852
Deferred Tax Liabilities		
Properties and equipment	691,818	1,207,545
Equity method investments	—	2,754
Total	691,818	1,210,299
Net deferred tax liabilities	$227,030	$579,447

As of December 31, 2017, the Company had alternative minimum tax ("AMT") credit carryforwards of $208.6 million, which do not expire and can be used to offset regular income taxes in future years. Under the new Tax Act, the Company may claim a refund of 50% of the remaining AMT credits (to the extent the credits exceed regular tax for the year) in 2018, 2019, and 2020. Any AMT credits remaining after 2020 will be refunded in 2021. The Company recorded a valuation allowance in December 2017 of $10.7 million to account for the sequestration reduction the Internal Revenue Service will apply to the refundable portion of the AMT credits.

As of December 31, 2017, the Company had gross federal net operating loss ("NOL") carryforwards of $839.3 million, which will not begin to expire until 2032. The Company also had gross state NOL carryforwards of $543.7 million, the majority of which will not expire until 2023 through 2037. The Company had $5.0 million of state NOL valuation allowances, and believes it is more likely than not that the remainder of the deferred tax benefits associated with federal and state NOL carryforwards will be utilized prior to their expiration.

Unrecognized Tax Benefits

The Company has unrecognized tax benefits of $0.7 million related to the allocation of certain gains associated with its divestitures for purposes of computing state income taxes. There was no change to the Company's unrecognized tax benefits during 2017, 2016 or 2015. If recognized, the net tax benefit of $0.7 million would not have a material effect on the Company's effective tax rate.

The Company files income tax returns in the U.S. federal, various states and other jurisdictions. The Company is no longer subject to examinations by state authorities before 2012 or by federal authorities before 2013. The Company is not currently under examination by the Internal Revenue Service. The Company believes that appropriate provisions have been made for all jurisdictions and all open years, and that any assessment on these filings will not have a material impact on the Company's financial position, results of operations or cash flows.

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11. Employee Benefit Plans

Postretirement Benefits

The Company provides certain health care benefits for retired employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. The health care plans are contributory, with participants' contributions adjusted annually. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. During the year ended December 31, 2017, the Company amended the plan to reflect a change from a Medicare Supplemental program to a Medicare Advantage program for participants age 65 and older. The coverage continues to be provided under a fully-insured arrangement. During the year ended December 31, 2016, the Company amended the plan to expand the eligibility definition to include those employees who have reached the age of 50 with at least 20 years of service.

The Company provided postretirement benefits to 340 retirees and their dependents at the end of 2017 and 310 retirees and their dependents at the end of 2016.

Obligations and Funded Status

The funded status represents the difference between the accumulated benefit obligation of the Company's postretirement plan and the fair value of plan assets at December 31. The postretirement plan does not have any plan assets; therefore, the unfunded status is equal to the amount of the December 31 accumulated benefit obligation.

The change in the Company's postretirement benefit obligation is as follows:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Change in Benefit Obligation			
Benefit obligation at beginning of year	$37,482	$36,626	$37,076
Service cost	1,508	2,323	1,808
Interest cost	1,097	1,498	1,448
Actuarial (gain) loss	5,156	(2,846)	(2,829)
Benefits paid	(1,204)	(934)	(877)
Curtailments[1]	(4,346)	—	—
Plan amendments	(8,643)	815	—
Benefit obligation at end of year	$31,050	$37,482	$36,626
Change in Plan Assets			
Fair value of plan assets at end of year	—	—	—
Funded status at end of year	$(31,050)	$(37,482)	$(36,626)

(1) During 2017, in conjunction with its sale of properties located in West Virginia, Virginia and Ohio, the Company terminated approximately 100 employees. As a result, the employees' participation in the postretirement plan also terminated, which resulted in a remeasurement and curtailment of the postretirement benefit obligation.

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet consist of the following:

	December 31,		
(In thousands)	2017	2016	2015
Current liabilities	$1,654	$1,223	$1,333
Long-term liabilities	29,396	36,259	35,293
	$31,050	$37,482	$36,626

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Amounts Recognized in Accumulated Other Comprehensive Income (Loss)

Amounts recognized in accumulated other comprehensive income (loss) consist of the following:

	December 31,		
(In thousands)	2017	2016	2015
Net actuarial (gain) loss	$1,912	$(2,266)	$580
Prior service cost	(5,206)	704	—
	$(3,294)	$(1,562)	$580

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income (Loss)

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Components of Net Periodic Postretirement Benefit Cost			
Service cost	$1,508	$2,323	$1,808
Interest cost	1,097	1,498	1,448
Amortization of prior service cost	(1,183)	111	—
Net periodic postretirement cost	1,422	3,932	3,256
Recognized curtailment gain	(4,917)	—	—
Total post retirement cost (income)	$(3,495)	$3,932	$3,256
Other Changes in Benefit Obligations Recognized in Other Comprehensive Income (Loss)			
Net (gain) loss	$4,178	$(2,846)	$(2,829)
Prior service cost	(8,643)	815	—
Amortization of prior service cost	2,733	(111)	—
Total recognized in other comprehensive income	(1,732)	(2,142)	(2,829)
Total recognized in net periodic benefit cost (income) and other comprehensive income	$(5,227)	$1,790	$427

Assumptions

Assumptions used to determine projected postretirement benefit obligations and postretirement costs are as follows:

	December 31,		
	2017	2016	2015
Discount rate[1]	3.85 %	4.30 %	4.25 %
Health care cost trend rate for medical benefits assumed for next year (pre-65)	7.50 %	7.50 %	5.50 %
Health care cost trend rate for medical benefits assumed for next year (post-65)	5.75 %	5.00 %	5.50 %
Ultimate trend rate (pre-65)	4.50 %	4.50 %	4.50 %
Ultimate trend rate (post-65)	4.50 %	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate (pre-65)	2030	2023	2018
Year that the rate reaches the ultimate trend rate (post-65)	2023	2018	2018

(1) Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2017, 2016 and 2015, respectively, the beginning of year discount rates of 3.85%, 4.25% and 4.00% were used.

Coverage provided to participants age 65 and older is under a fully-insured arrangement. The Company subsidy is limited to 60% of the expected annual fully-insured premium for participants age 65 and older. For all participants under age 65, the Company subsidy for all retiree medical and prescription drug benefits, beginning January 1, 2006, was limited to an aggregate annual amount not to exceed $648,000. This limit increases by 3.5% annually thereafter.

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Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In thousands)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost	$ 141	$ (106)
Effect on postretirement benefit obligation	4,689	(3,716)

Cash Flows

Contributions. The Company expects to contribute approximately $1.7 million to the postretirement benefit plan in 2018.

Estimated Future Benefit Payments. The following estimated benefit payments under the Company's postretirement plans, which reflect expected future service, are expected to be paid as follows:

(In thousands)	
2018	$1,686
2019	1,816
2020	1,873
2021	1,898
2022	2,002
Years 2023 - 2027	9,237

Savings Investment Plan

The Company has a Savings Investment Plan (SIP), which is a defined contribution plan. The Company matches a portion of employees' contributions in cash. Participation in the SIP is voluntary and all regular employees of the Company are eligible to participate. The Company matches employee contributions dollar-for-dollar, up to the maximum IRS limit, on the first six percent of an employee's pretax earnings. The SIP also provides for discretionary profit sharing contributions in an amount equal to nine percent of an eligible plan participant's salary and bonus. In November 2017, the Compensation Committee of the Board of Directors approved an increase in the discretionary profit sharing contribution from 9 percent to 10 percent for 2018 contributions. During the years ended December 31, 2017, 2016 and 2015, the Company made contributions of $6.5 million, $6.5 million and $7.1 million, respectively, which are included in general and administrative expense in the Consolidated Statement of Operations. The Company's common stock is an investment option within the SIP.

Deferred Compensation Plan

The Company has a deferred compensation plan which is available to officers and certain members of the Company's management group and acts as a supplement to the SIP. The Internal Revenue Code does not cap the amount of compensation that may be taken into account for purposes of determining contributions to the deferred compensation plan and does not impose limitations on the amount of contributions to the deferred compensation plan. At the present time, the Company anticipates making a contribution to the deferred compensation plan on behalf of a participant in the event that Internal Revenue Code limitations cause a participant to receive less than the Company matching contribution under the SIP.

The assets of the deferred compensation plan are held in a rabbi trust and are subject to additional risk of loss in the event of bankruptcy or insolvency of the Company.

Under the deferred compensation plan, the participants direct the deemed investment of amounts credited to their accounts. The trust assets are invested in either mutual funds that cover the investment spectrum from equity to money market, or may include holdings of the Company's common stock, which is funded by the issuance of shares to the trust. The mutual funds are publicly traded and have market prices that are readily available. The Company's common stock is not currently an investment option in the deferred compensation plan. Shares of the Company's stock currently held in the deferred compensation plan represent vested performance share awards that were previously deferred into the rabbi trust. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments. The market value of the trust assets, excluding the Company's common stock, was $15.0 million and $12.6 million at December 31, 2017 and 2016, respectively, and is included in other assets in the Consolidated Balance Sheet. Related liabilities, including the Company's common stock, totaled $29.1 million and $24.2 million at

December 31, 2017 and 2016, respectively, and are included in other liabilities in the

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Consolidated Balance Sheet. With the exception of the Company's common stock, there is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets because the changes in market value of the trust assets are offset completely by changes in the value of the liability, which represents trust assets belonging to plan participants.

As of December 31, 2017 and 2016, 495,774 shares and 495,774 shares of the Company's common stock were held in the rabbi trust, respectively. These shares were recorded at the market value on the date of deferral, which totaled $5.1 million and $5.1 million at December 31, 2017 and 2016, respectively, and is included in additional paid-in capital in stockholders' equity in the Consolidated Balance Sheet. The Company recognized compensation expense (benefit) of $2.6 million, $1.8 million and $(6.4) million in 2017, 2016 and 2015, respectively, which is included in general and administrative expense in the Consolidated Statement of Operations representing the increase (decrease) in the closing price of the Company's shares held in the trust. The Company's common stock issued to the trust is not considered outstanding for purposes of calculating basic earnings per share, but is considered a common stock equivalent in the calculation of diluted earnings per share.

The Company made contributions to the deferred compensation plan of $1.0 million, $0.6 million and $1.0 million in 2017, 2016 and 2015, respectively, which are included in general and administrative expense in the Consolidated Statement of Operations.

12. Capital Stock

Common Stock Issuance

On February 22, 2016, the Company entered into an underwriting agreement, pursuant to which the Company sold an aggregate of 44.0 million shares of common stock at a price to the Company of $19.675 per share. On February 26, 2016, the Company received $865.7 million in net proceeds, after deducting underwriting discounts and commissions. On March 2, 2016, the Company sold an additional 6.6 million shares of common stock as a result of the exercise of the underwriters’ option to purchase additional shares and received $129.9 million in net proceeds. These net proceeds were used for general corporate purposes, including repaying indebtedness under the Company’s revolving credit facility and repurchasing certain of the Company's senior notes.

Incentive Plans

On May 1, 2014, the Company’s shareholders approved the 2014 Incentive Plan, which replaced the 2004 Incentive Plan that expired on April 29, 2014. Under the 2014 Incentive Plan, incentive and non-statutory stock options, stock appreciation rights (SARs), stock awards, cash awards and performance share awards may be granted to key employees, consultants and officers of the Company. Non-employee directors of the Company may be granted discretionary awards under the 2014 Incentive Plan consisting of stock options or stock awards. A total of 18.0 million shares of common stock may be issued under the 2014 Incentive Plan. Under the 2014 Incentive Plan, no more than 10.0 million shares may be issued pursuant to incentive stock options. No additional awards may be granted under the 2014 Incentive Plan on or after May 1, 2024. At December 31, 2017, approximately 14.8 million shares are available for issuance under the 2014 Incentive Plan.

No additional awards will be granted under any of the Company’s prior plans, including the 2004 Incentive Plan. Awards outstanding under the 2004 Incentive Plan will remain outstanding in accordance with their original terms and conditions.

Treasury Stock

In August 1998, the Board of Directors authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. The timing and amount of these stock purchases are determined at the discretion of management. The Company may use the repurchased shares to fund stock compensation programs presently in existence, or for other corporate purposes. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase shares of the Company.

During the year ended December 31, 2017, the Company repurchased 5.0 million shares for a total cost of $123.7 million. During 2016 and 2015, there were no share repurchases. Since the authorization date, the Company has repurchased 34.9 million shares of the 40.0 million total shares authorized, of which 20.0 million shares have been retired, for a total cost of approximately $512.1 million. No treasury shares have been delivered or sold by the

Company subsequent to the repurchase. As of December 31, 2017, 14.9 million shares were held as treasury stock. In February 2018, the Board of Directors authorized an increase of 25.0 million shares to the Company's share repurchase program. After this authorization, the total number of shares available for repurchase is 30.1 million shares.

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Dividend Restrictions

The Board of Directors of the Company determines the amount of future cash dividends, if any, to be declared and paid on the common stock depending on, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures, and its future business prospects. None of the senior note or credit agreements in place have restricted payment provisions or other provisions limiting dividends.

13. Stock-Based Compensation

General

Stock-based compensation expense for the years ended December 31, 2017, 2016 and 2015 was $34.0 million, $26.0 million and $13.7 million, respectively, and is included in general and administrative expense in the Consolidated Statement of Operations.

As described in Note 1 to the Consolidated Financial Statements, effective January 1, 2017, the Company adopted ASU No. 2016-09, which requires that excess tax benefits and tax deficiencies on stock-based compensation be recorded in the income statement. For the year ended December 31, 2017, the Company recorded an increase to tax expense of $3.0 million in the Consolidated Statement of Operations as a result of book compensation cost for employee stock-based compensation exceeding the federal and state tax deductions for awards that vested during the period.

Prior to the adoption of ASU No. 2016-09, windfall tax benefits were recorded in additional paid in capital in the Consolidated Balance Sheet and tax shortfalls reduced additional paid in capital to the extent they offset previously recorded windfall tax benefits. For the year ended December 31, 2016, the Company recorded a tax deficiency of $2.1 million, resulting in a reduction of the Company's windfall tax benefit that was recorded in additional paid in capital in the Consolidated Balance Sheet. The tax deficiency was a result of book compensation cost for employee stock-based compensation exceeding the federal and state tax deductions for certain awards that vested during the period. There was no tax benefit or deficiency recognized from stock-based compensation vesting during the year ended December 31, 2015.

Restricted Stock Awards

Restricted stock awards are granted from time to time to employees of the Company. The fair value of restricted stock grants is based on the closing stock price on the grant date. Restricted stock awards generally vest either at the end of a three year service period or on a graded or graduated vesting basis at each anniversary date over a three or four year service period.

For awards that vest at the end of the service period, expense is recognized ratably using a straight-line approach over the service period. Under the graded or graduated approach, the Company recognizes compensation cost ratably over the requisite service period, as applicable, for each separately vesting tranche as though the awards are, in substance, multiple awards. For most restricted stock awards, vesting is dependent upon the employees' continued service with the Company, with the exception of employment termination due to death, disability or retirement. If included in the grant award, the Company accelerates the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company's stock-based compensation programs.

The Company used an annual forfeiture rate assumption of 5.0% for purposes of recognizing stock-based compensation expense for restricted stock awards. The annual forfeiture rates were based on the Company's actual forfeiture history for this type of award to various employee groups.

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The following table is a summary of restricted stock award activity:

	Year Ended December 31,					
	2017		2016		2015	
	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	43,175	$ 33.87	49,825	$ 33.76	49,869	$ 33.40
Granted	158,500	28.05	—	—	5,900	25.44
Vested	(40,225)	34.49	(6,650)	33.02	(5,944)	22.55
Forfeited	—	—	—	—	—	—
Outstanding at end of period(1)(2)	161,450	$ 28.00	43,175	$ 33.87	49,825	$ 33.76

(1) As of December 31, 2017, the aggregate intrinsic value was $4.6 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2017 by the number of non-vested restricted stock awards outstanding.

(2) As of December 31, 2017, the weighted average remaining contractual term of non-vested restricted stock awards outstanding was 1.4 years.

Compensation expense recorded for all restricted stock awards for the years ended December 31, 2017, 2016 and 2015 was $0.5 million, $0.4 million and $0.4 million, respectively. Unamortized expense as of December 31, 2017 for all outstanding restricted stock awards was $4.0 million and will be recognized over the next two years.

The total fair value of restricted stock awards that vested during 2017, 2016 and 2015 was $0.9 million, $0.2 million and $0.2 million, respectively.

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. The fair value of the restricted stock units is based on the closing stock price on the grant date. These units vest immediately and compensation expense is recorded immediately. Restricted stock units are issued when the director ceases to be a director of the Company.

The following table is a summary of restricted stock unit activity:

	Year Ended December 31,					
	2017		2016		2015	
	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	348,538	$ 15.01	425,438	$ 13.81	604,214	$ 12.48
Granted and fully vested	59,025	23.04	69,302	20.62	51,292	27.87
Issued	—	—	(146,202)	14.17	(230,068)	13.45
Forfeited	—	—	—	—	—	—
Outstanding at end of period(1)(2)	407,563	$ 16.17	348,538	$ 15.01	425,438	$ 13.81

(1) As of December 31, 2017, the aggregate intrinsic value was $11.7 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2017 by the number of outstanding restricted stock units.

(2)

Due to the immediate vesting of the units and the unknown term of each director, the weighted-average remaining contractual term in years has not been provided.

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Compensation expense recorded for all restricted stock units for the year ended December 31, 2017, 2016 and 2015 was $1.4 million, $1.4 million and $1.4 million, respectively, which reflects the total fair value of these units.

Stock Appreciation Rights

Stock appreciation rights (SARs) allow the employee to receive any intrinsic value over the grant date market price that may result from the price appreciation of the common shares granted. All of these awards have graded-vesting features and vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant and have a contractual term of seven years. The Company no longer grants SARs to employees.

The following table is a summary of SAR activity:

	Year Ended December 31,					
	2017		2016		2015	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of period	483,286	$ 13.04	558,546	$ 12.52	667,764	$ 12.63
Granted	—	—	—	—	—	—
Exercised	(426,142)	12.43	(75,260)	9.19	(109,218)	13.19
Forfeited or expired	—	—	—	—	—	—
Outstanding at end of period(1)	57,144	$ 17.59	483,286	$ 13.04	558,546	$ 12.52
Exercisable at end of period(2)	57,144	$ 17.59	483,286	$ 13.04	558,546	$ 12.52

(1) The intrinsic value of a SAR is the amount which the current market value of the underlying stock exceeds the exercise price of the SAR. As of December 31, 2017, the aggregate intrinsic value and weighted-average remaining contractual term of SARs outstanding was $0.6 million and 1.1 years, respectively.

(2) As of December 31, 2017, the aggregate intrinsic value and weighted-average remaining contractual term of SARs exercisable was $0.6 million and 1.1 years, respectively.

The expected term was derived by reviewing minimum and maximum expected term outputs from the Black-Scholes model based on award type and employee type. This term represents the period of time that awards granted are expected to be outstanding. The stock price volatility was calculated using historical closing stock price data for the Company for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the U.S. Treasury within the expected term as measured on the grant date. The expected dividend percentage assumes that the Company will continue to pay a consistent level of dividend each quarter.

Performance Share Awards

The Company grants three types of performance share awards: two based on performance conditions measured against the Company's internal performance metrics (Employee Performance Share Awards and Hybrid Performance Share Awards) and one based on market conditions measured based on the Company's performance relative to a predetermined peer group (TSR Performance Share Awards). The performance period for these awards commences on January 1 of the respective year in which the award was granted and extends over a three-year performance period. For all performance share awards, the Company used an annual forfeiture rate assumption ranging from 0% to 5% for purposes of recognizing stock-based compensation expense for its performance share awards.

Performance Share Awards Based on Internal Performance Metrics

The fair value of performance share award grants based on internal performance metrics is based on the closing stock price on the grant date. Each performance share award represents the right to receive up to 100% of the award in shares of common stock.

Employee Performance Share Awards. The Employee Performance Share Awards vest at the end of the three-year performance period. An employee will earn one-third of the award for each of the three performance metrics that the Company meets. These performance metrics are set by the Company's Compensation Committee and are based on the

Company's average production, average finding costs and average reserve replacement over a three-year performance period. Based on the

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Company's probability assessment at December 31, 2017, it is considered probable that all of the criteria for these awards will be met.

The following table is a summary of activity for Employee Performance Share Awards:

	Year Ended December 31,					
	2017		2016		2015	
	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	993,530	$ 27.26	925,590	$ 30.23	1,088,960	$ 25.18
Granted	406,460	22.60	435,990	20.49	349,780	27.71
Issued and fully vested	(225,780)	39.43	(340,960)	26.62	(504,620)	17.59
Forfeited	(78,240)	23.20	(27,090)	27.77	(8,530)	31.11
Outstanding at end of period	1,095,970	$ 23.31	993,530	$ 27.26	925,590	$ 30.23

Hybrid Performance Share Awards. The Hybrid Performance Share Awards have a three-year graded performance period. The awards vest 25% on each of the first and second anniversary dates and 50% on the third anniversary provided that the Company has $100 million or more of operating cash flow for the year preceding the vesting date, as set by the Company's Compensation Committee. If the Company does not meet the performance metric for the applicable period, then the portion of the performance shares that would have been issued on that anniversary date will be forfeited. Based on the Company's probability assessment at December 31, 2017, it is considered probable that the criteria for these awards will be met.

The following table is a summary of activity for the Hybrid Performance Share Awards:

	Year Ended December 31,					
	2017		2016		2015	
	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	479,784	$ 25.12	372,385	$ 30.37	329,061	$ 29.27
Granted	272,920	22.60	271,938	20.49	194,947	27.71
Issued and fully vested	(178,350)	29.01	(164,539)	29.34	(151,623)	24.56
Forfeited	—	—	—	—	—	—
Outstanding at end of period	574,354	$ 22.72	479,784	$ 25.12	372,385	$ 30.37

Performance Share Awards Based on Market Conditions

These awards have both an equity and liability component, with the right to receive up to the first 100% of the award in shares of common stock and the right to receive up to an additional 100% of the value of the award in excess of the equity component in cash. The equity portion of these awards is valued on the grant date and is not marked to market, while the liability portion of the awards is valued as of the end of each reporting period on a mark-to-market basis. The Company calculates the fair value of the equity and liability portions of the awards using a Monte Carlo simulation model.

TSR Performance Share Awards. The TSR Performance Share Awards granted are earned, or not earned, based on the comparative performance of the Company's common stock measured against a predetermined group of companies in the Company's peer group over a three-year performance period.

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The following table is a summary of activity for the TSR Performance Share Awards:

	Year Ended December 31,					
	2017		2016		2015	
	Shares	Weighted-Average Grant Date Fair Value per Share(1)	Shares	Weighted-Average Grant Date Fair Value per Share(1)	Shares	Weighted-Average Grant Date Fair Value per Share(1)
Outstanding at beginning of period	885,213	$ 21.62	732,286	$ 23.82	674,787	$ 22.42
Granted	409,380	19.85	407,907	18.57	292,421	19.29
Issued and fully vested	(157,147)	32.04	(254,980)	23.06	(234,922)	14.16
Forfeited	(27,738)	32.04	—	—	—	—
Outstanding at end of period	1,109,708	$ 19.23	885,213	$ 21.62	732,286	$ 23.82

(1) The grant date fair value figures in this table represent the fair value of the equity component of the performance share awards.

The current portion of the liability, included in accrued liabilities in the Consolidated Balance Sheet at December 31, 2017 was $3.3 million. There was no current liability as of December 31, 2016. The non-current portion of the liability for the TSR Performance Share Awards, included in other liabilities in the Consolidated Balance Sheet at December 31, 2017 and 2016, was $6.6 million and $2.1 million, respectively. The Company made cash payments during the years ended December 31, 2016 and 2015 of $1.8 million and $7.0 million, respectively. There were no cash payments made during the year ended December 31, 2017.

The following assumptions were used to determine the grant date fair value of the equity component of the TSR Performance Share Awards for the respective periods:

	Year Ended December 31,		
	2017	2016	2015
Fair value per performance share award granted during the period	$19.85	$18.57	$19.29
Assumptions			
Stock price volatility	37.8 %	34.4 %	32.3 %
Risk free rate of return	1.4 %	0.9 %	1.0 %
Expected dividend yield	— %	— %	0.3 %

The following assumptions were used to determine the fair value of the liability component of the TSR Performance Share Awards for the respective periods:

	December 31,		
	2017	2016	2015
Fair value per performance share award at the end of the period	$13.23 - $21.64	$5.59 - $7.10	$2.49 - $6.39
Assumptions			
Stock price volatility	29.1% - 36.7%	40.4% - 43.0%	33.5% - 37.5%
Risk free rate of return	1.8% - 1.9%	0.9% - 1.2%	0.7% - 1.1%
Expected dividend yield	—%	—%	—%

The stock price volatility was calculated using historical closing stock price data for the Company for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the U.S. Treasury within the expected term as measured on the grant date. The expected dividend percentage assumes that the Company will continue to pay a consistent level of dividend each quarter.

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Other Information

Compensation expense recorded for both the equity and liability components of all performance share awards for the years ended December 31, 2017, 2016 and 2015 was $29.1 million, $21.3 million and $18.3 million, respectively. Total unamortized compensation expense related to the equity component of performance shares at December 31, 2017 was $20.7 million and will be recognized over the next 0.9 years.

As of December 31, 2017, the aggregate intrinsic value for all performance share awards was $79.5 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2017 by the number of unvested performance share awards outstanding. As of December 31, 2017, the weighted average remaining contractual term of unvested performance share awards outstanding was approximately 1.2 years

On December 31, 2017, the performance period ended for two types of performance share awards that were granted in 2015. For the Employee Performance Share Awards, the calculation of the three-year average of the three internal performance metrics was completed in the first quarter of 2018 and was certified by the Compensation Committee in February 2018. As the Company achieved the three performance metrics, 317,790 shares with a grant date fair value of $8.8 million were issued in February 2018. For the TSR Performance Share Awards, 292,421 shares with a grant date fair value of $5.6 million were issued in January 2018 based on the Company's ranking relative to a predetermined peer group. Cash payments associated with these awards in the amount of $3.3 million were also made in January 2018 due to the Company's ranking relative to the peer group being above the median. The calculation of the award payout was certified by the Compensation Committee on January 5, 2018.

Deferred Performance Shares

As of December 31, 2017, 495,774 shares of the Company's common stock representing vested performance share awards were deferred into the deferred compensation plan. During 2017, 0 shares were sold out of the plan. During 2017, an increase to the deferred compensation liability of $2.6 million was recognized, which represents the increase in the closing price of the Company's shares held in the trust during the period. The increase in compensation expense was included in general and administrative expense in the Consolidated Statement of Operations.

14. Earnings per Common Share

Basic earnings per share (EPS) is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted EPS is similarly calculated except that the common shares outstanding for the period is increased using the treasury stock method to reflect the potential dilution that could occur if outstanding stock appreciation rights were exercised and stock awards were vested at the end of the applicable period.

Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted income or loss per share as their impact would be anti-dilutive.

The following is a calculation of basic and diluted weighted-average shares outstanding:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Weighted-average shares - basic	463,735	456,847	413,696
Dilution effect of stock appreciation rights and stock awards at end of period	1,816	—	—
Weighted-average shares - diluted	465,551	456,847	413,696

The following is a calculation of weighted-average shares excluded from diluted EPS due to the anti-dilutive effect:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Weighted-average stock appreciation rights and stock awards excluded from diluted EPS due to the anti-dilutive effect due to net loss	—	1,478	1,481
Weighted-average stock appreciation rights and stock awards excluded from diluted EPS due to the anti-dilutive effect calculated using the treasury stock method	28	1	2
Weighted-average stock appreciation rights and stock awards excluded from diluted EPS due to the anti-dilutive effect	28	1,479	1,483

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15. Accumulated Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive income (loss) by component, net of tax, were as follows:

(In thousands)	Postretirement Benefits
Balance at December 31, 2014	$ (2,151)
Other comprehensive income (loss) before reclassifications	1,786
Net current-period other comprehensive income (loss)	1,786
Balance at December 31, 2015	$ (365)
Other comprehensive income (loss) before reclassifications	1,280
Amounts reclassified from accumulated other comprehensive income (loss)	70
Net current-period other comprehensive income	1,350
Balance at December 31, 2016	$ 985
Other comprehensive income (loss) before reclassifications	2,815
Amounts reclassified from accumulated other comprehensive income (loss)	(1,723)
Net current-period other comprehensive income	1,092
Balance at December 31, 2017	$ 2,077

Amounts reclassified from accumulated other comprehensive income (loss) into the Consolidated Statement of Operations were as follows:

	Year Ended December 31,			Affected Line Item in the Consolidated Statement of Operations
(In thousands)	2017	2016	2015	
Postretirement benefits				
Amortization of prior service cost	2,733	(111)	—	General and administrative expense
Total before tax	2,733	(111)	—	Income (loss) before income taxes
	(1,010)	41	—	Income tax benefit (expense)
Total reclassifications for the period	$1,723	$(70)	$ —	Net income (loss)

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16. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

	December 31,	
(In thousands)	2017	2016
Accounts receivable, net		
Trade accounts	$215,511	$185,594
Joint interest accounts	467	1,359
Other accounts	1,312	5,335
	217,290	192,288
Allowance for doubtful accounts	(1,286)	(1,243)
	$216,004	$191,045
Inventories		
Tubular goods and well equipment	$8,006	$11,005
Natural gas in storage	—	2,299
	$8,006	$13,304
Other assets		
Deferred compensation plan	$14,966	$12,587
Debt issuance cost	7,990	11,403
Derivative instruments	2,239	2,991
Other accounts	56	58
	$25,251	$27,039
Accounts payable		
Trade accounts	$7,815	$27,355
Natural gas purchases	4,299	2,231
Royalty and other owners	39,207	36,472
Accrued transportation	51,433	48,977
Accrued capital costs	31,130	34,647
Taxes other than income	16,801	13,827
Deposits received for asset sales	81,500	—
Other accounts	5,860	4,902
	$238,045	$168,411
Accrued liabilities		
Employee benefits	$20,645	$14,153
Taxes other than income	550	3,829
Asset retirement obligations	4,952	2,000
Other accounts	1,294	1,510
	$27,441	$21,492
Other liabilities		
Deferred compensation plan	$29,145	$24,169
Other accounts	10,578	4,952
	$39,723	$29,121

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17. Supplemental Cash Flow Information

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Cash paid for interest and income taxes			
Interest	$79,846	$86,723	$92,749
Income taxes	40,626	688	7,550
Non-cash investing activities			
Change in accrued capital costs	(3,516)	7,168	(194,947)

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CABOT OIL & GAS CORPORATION
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)
Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Estimates of total proved reserves at December 31, 2017, 2016 and 2015 were based on studies performed by the Company's petroleum engineering staff. The estimates were computed using the 12-month average index price for the respective commodity, calculated as the unweighted arithmetic average for the first day of the month price for each month during the respective year. The estimates were audited by Miller and Lents, Ltd. (Miller and Lents), who indicated that based on their investigation and subject to the limitations described in their audit letter, they believe the results of those estimates and projections were reasonable in the aggregate.

No major discovery or other favorable or unfavorable event after December 31, 2017, is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

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The following tables illustrate the Company's net proved reserves, including changes, and proved developed and proved undeveloped reserves for the periods indicated, as estimated by the Company's engineering staff. All reserves are located within the continental United States.

	Natural Gas (Bcf)	Crude Oil & NGLs (Mbbl)(1)	Total (Bcfe)(2)
December 31, 2014	7,082	53,136	7,401
Revision of prior estimates(3)	444	(3,008)	426
Extensions, discoveries and other additions(4)	896	11,511	965
Production	(566)	(6,096)	(603)
Purchases of reserves in place	—	187	1
December 31, 2015	7,856	55,730	8,190
Revision of prior estimates(5)	405	(5,867)	370
Extensions, discoveries and other additions(4)	650	5,540	684
Production	(600)	(4,454)	(627)
Sales of reserves in place	(30)	(1,777)	(41)
December 31, 2016	8,281	49,172	8,576
Revision of prior estimates(6)	917	1,892	928
Extensions, discoveries and other additions(4)	1,138	16,329	1,236
Production	(655)	(4,953)	(685)
Sales of reserves in place(7)	(328)	(188)	(329)
December 31, 2017	9,353	62,252	9,726
Proved Developed Reserves (8)			
December 31, 2014	4,339	27,221	4,502
December 31, 2015	4,676	25,586	4,829
December 31, 2016	5,500	20,442	5,623
December 31, 2017	6,001	31,066	6,187
Proved Undeveloped Reserves(9)			
December 31, 2014	2,743	25,915	2,898
December 31, 2015	3,180	30,144	3,361
December 31, 2016	2,781	28,730	2,953
December 31, 2017	3,352	31,186	3,539

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(1) NGL reserves were less than 1.0% of the Company's total proved equivalent reserves for 2017, 2016 and 2015 and 13.7%, 13.6% and 16.1% of the Company's proved crude oil and NGL reserves for 2017, 2016 and 2015, respectively.

(2) Includes natural gas and natural gas equivalents determined by using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or NGLs.

(3) The net upward revision of 425.6 Bcfe was primarily due to an upward performance revision of 702.9 Bcfe associated with positive drilling results in the Dimock field in northeast Pennsylvania, partially offset by a downward revision of 277.3 Bcfe associated with lower commodity prices.

(4) Extensions, discoveries and other additions were primarily related to drilling activity in the Dimock field located in northeast Pennsylvania. The Company added 1,129.2 Bcfe, 647.7 Bcfe and 890.6 Bcfe of proved reserves in this field in 2017, 2016 and 2015, respectively.

(5) The net upward revision of 370.1 Bcfe was primarily due to an upward performance revision of 658.7 Bcfe associated with positive drilling results in the Dimock field in northeast Pennsylvania, partially offset by a downward revision of 246.0 Bcfe associated with PUD reclassifications and 42.6 Bcfe associated with lower commodity prices.

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(6) The net upward revision of 928.5 Bcfe was primarily due to an upward revision of 863.8 Bcfe associated with positive drilling results in the Dimock field in northeast Pennsylvania and 103.0 Bcfe associated with higher commodity prices, partially offset by a downward revision of 38.3 Bcfe associated with PUD reclassifications.

(7) Sales of reserves in place were primarily related to the divestiture of certain oil and gas properties in West Virginia, Virginia and Ohio in September 2017 which represented 321.8 Bcfe.

(8) Includes proved developed reserves of 20.3 natural gas (Bcf), 31.1 (Mbbl) and 206.7 (Total Bcfe), which were classified as held for sale at December 31, 2017.

(9) Includes proved undeveloped reserves of 17.6 natural gas (Bcf), 31.2 (Mbbl) and 204.8 (Total Bcfe), which were classified as held for sale at December 31, 2017.

Capitalized Costs Relating to Oil and Gas Producing Activities

Capitalized costs relating to oil and gas producing activities and related accumulated depreciation, depletion and amortization were as follows:

	December 31,		
(In thousands)	2017	2016	2015
Aggregate capitalized costs relating to oil and gas producing activities	$7,472,653	$7,958,548	$9,554,584
Aggregate accumulated depreciation, depletion and amortization	(3,630,855)	(3,717,342)	(4,586,958)
Net capitalized costs	$3,841,798	$4,241,206	$4,967,626

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Property acquisition costs, proved	$—	$—	$16,312
Property acquisition costs, unproved	102,265	2,703	20,097
Exploration costs	41,232	27,640	34,003
Development costs	617,500	359,501	723,451
Total costs	$760,997	$389,844	$793,863

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

The following information has been developed based on natural gas and crude oil reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- Future costs and selling prices will differ from those required to be used in these calculations.
- Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations.
- Selection of a 10% discount rate is arbitrary and may not be a reasonable measure of the relative risk that is part of realizing future net oil and gas revenues.
- Future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by using the 12-month average index price for the respective commodity, calculated as the unweighted arithmetic average for the first day of the month price for each month during the year.

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The average prices (adjusted for basis and quality differentials) related to proved reserves are as follows:

	Year Ended December 31,		
	2017	2016	2015
Natural gas	$2.33	$1.74	$1.81
Crude oil	$49.26	$37.54	$47.10
NGLs	$20.64	$10.69	$12.98

In the above table, natural gas prices are stated per Mcf and crude oil and NGL prices are stated per barrel.

Future cash inflows were reduced by estimated future development and production costs based on year end costs to arrive at net cash flow before tax. Future income tax expense was computed by applying year end statutory tax rates to future pretax net cash flows, less the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations. The applicable accounting standards require the use of a 10% discount rate.

Management does not solely use the following information when making investment and operating decisions. These decisions are based on a number of factors, including estimates of proved reserves, and varying price and cost assumptions considered more representative of a range of anticipated economic conditions.

Standardized Measure is as follows:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Future cash inflows	$24,602,423	$16,078,109	$16,516,696
Future production costs	(9,080,268)	(7,821,889)	(7,934,427)
Future development costs	(1,901,647)	(1,926,465)	(2,053,562)
Future income tax expenses	(2,585,022)	(1,441,425)	(1,263,452)
Future net cash flows	11,035,486	4,888,330	5,265,255
10% annual discount for estimated timing of cash flows	(6,025,040)	(2,653,563)	(2,406,423)
Standardized measure of discounted future net cash flows	$5,010,446	$2,234,767	$2,858,832

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

The following is an analysis of the changes in the Standardized Measure:

	Year Ended December 31,		
(In thousands)	2017	2016	2015
Beginning of year	$2,234,767	$2,858,832	$6,493,006
Discoveries and extensions, net of related future costs	729,429	147,664	305,607
Net changes in prices and production costs	2,709,183	(240,050)	(7,329,445)
Accretion of discount	261,504	285,883	862,078
Revisions of previous quantity estimates	538,318	120,800	161,379
Timing and other	(71,407)	(154,966)	427,073
Development costs incurred	405,264	238,118	498,350
Sales and transfers, net of production costs	(1,126,520)	(631,912)	(690,618)
Net purchases (sales) of reserves in place	(95,128)	(9,326)	3,623
Net change in income taxes	(574,964)	(380,276)	2,127,779
End of year	$5,010,446	$2,234,767	$2,858,832

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CABOT OIL & GAS CORPORATION
SELECTED DATA
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
2017					
Operating revenues	$517,843	$460,457	$385,416	$400,503	$1,764,219
Impairment of oil and gas properties and other assets[1]	—	68,555	—	414,256	482,811
Earnings (loss) on equity method investments[2]	(1,283)	(1,286)	(1,417)	(96,500)	(100,486)
Operating income (loss)	190,120	57,440	39,986	(438,806)	(151,260)
Net income (loss)[3]	105,720	21,527	17,587	(44,441)	100,393
Basic earnings (loss) per share	0.23	0.05	0.04	(0.10)	0.22
Diluted earnings (loss) per share	0.23	0.05	0.04	(0.10)	0.22
2016					
Operating revenues	$281,941	$246,816	$310,429	$316,491	$1,155,677
Impairment of oil and gas properties[1]	—	—	—	435,619	435,619
Operating income (loss)	(55,086)	(70,382)	3,598	(443,075)	(564,945)
Net income (loss)	(51,194)	(62,910)	(10,260)	(292,760)	(417,124)
Basic earnings (loss) per share	(0.12)	(0.14)	(0.02)	(0.63)	(0.91)
Diluted earnings (loss) per share	(0.12)	(0.14)	(0.02)	(0.63)	(0.91)

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(1) For discussion of impairment of oil and gas properties and other assets, refer to Note 3 of the Notes to the Consolidated Financial Statements.

(2) Earnings (loss) on equity method investments in fourth quarter of 2017 includes an other than temporary impairment of $95.9 million associated with the Company's investment in Constitution. Refer to Note 4 of the Notes to the Consolidated Financial Statements.

(3) Net income (loss) in the fourth quarter of 2017 includes an income tax benefit of $242.9 million as a result of the remeasurement of the Company's net deferred income tax liabilities based on the new lower corporate income tax rate associated with the Tax Act enacted in December 2017.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures and Changes in Internal Control over Financial Reporting

As of December 31, 2017, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission's rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

There were no changes in the Company's internal control over financial reporting that occurred during the fourth quarter that have materially affected, or are reasonably likely to materially effect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

The management of Cabot Oil & Gas Corporation is responsible for establishing and maintaining adequate internal control over financial reporting. Cabot Oil & Gas Corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Cabot Oil & Gas Corporation's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on this assessment management has concluded that, as of December 31, 2017, the Company's internal control over financial reporting is effective at a reasonable assurance level based on those criteria.

The effectiveness of Cabot Oil & Gas Corporation's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2018 annual stockholders' meeting. In addition, the information set forth under the caption "Business—Other Business Matters—Corporate Governance Matters" in Item 1 regarding our Code of Business Conduct is incorporated by reference in response to this Item.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2018 annual stockholders' meeting.

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

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2018 annual stockholders' meeting.

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

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2018 annual stockholders' meeting.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2018 annual stockholders' meeting.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

A. INDEX

1. Consolidated Financial Statements

See Index on page 56.

2. Financial Statement Schedules

Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

3. Exhibits

The following instruments are included as exhibits to this report. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, copies of the instrument have been included herewith. Our Commission file number is 1-10447.

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of December 19, 2017, between the Company and VOG Palo Verde L.P. (Form 8-K filed on December 22, 2017).
3.1	Restated Certificate of Incorporation of the Company (Form 8-K filed on January 22, 2010).
3.2	Certificate of Amendment of Restated Certificate of Incorporation, dated as of May 1, 2012 (Form 10-Q for the quarter ended June 30, 2012).
3.3	Certificate of Amendment of Restated Certificate of Incorporation, dated as of May 1, 2014 (Form 10-Q for the quarter ended June 30, 2014).
3.4	Amended and Restated Bylaws of Cabot Oil & Gas Corporation (Form 8-K filed on July 29, 2016).
4.1	Form of Certificate of Common Stock of the Company (Registration Statement No. 33-32553).
4.2	Note Purchase Agreement dated as of July 16, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K for July 22, 2008).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010 (Form 10-Q for the quarter ended June 30, 2010).
	(b) Amendment No. 2 to Note Purchase Agreement, dated as of December 31, 2015 (Form 8-K filed February 9, 2016).
	(c) Amendment No. 3 to Note Purchase Agreement, dated as of April 6, 2016 (Form 10-Q for the quarter ended March 31, 2016).
4.3	Note Purchase Agreement dated as of December 1, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 10-K for 2008).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010 (Form 10-Q for the quarter ended June 30, 2010).
	(b) Amendment No. 2 to Note Purchase Agreement, dated as of December 31, 2015 (Form 8-K filed on February 9, 2016).
	(c) Amendment No. 3 to Note Purchase Agreement, dated as of April 6, 2016 (Form 10-Q for the quarter ended March 31, 2016).
4.4	Note Purchase Agreement dated as of December 30, 2010 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 10-K for 2010).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of December 31, 2015 (Form 8-K filed on February 9, 2016).
	(b) Amendment No. 2 to Note Purchase Agreement, dated as of April 6, 2016 (Form 10-Q for the quarter ended March 31, 2016).

4.5	Note Purchase Agreement dated as of September 18, 2014 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K filed on September 24, 2014).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of December 31, 2015 (Form 8-K filed on February 9, 2016).
	(b) Amendment No. 2 to Note Purchase Agreement, dated as of April 6, 2016 (Form 10-Q for the quarter ended March 31, 2016).
*10.1	Form of Change in Control Agreement between the Company and Certain Officers (Form 10-K for 2008).
	(a) Form of Change in Control Agreement between the Company and Certain Officers (Confirmation that Certain Benefits no Longer Apply) (Form 10-K for 2010).
*10.2	Form of Indemnity Agreement between the Company and Certain Officers (Form 10-K for 2012).
*10.3	Deferred Compensation Plan of the Company, as Amended and Restated, Effective January 1, 2011 (Form 10-Q for the quarter ended June 30, 2011).
*10.4	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001 (Form 10-K for 2001).
	(a) Amendment to Employment Agreement between the Company and Dan O. Dinges, effective December 31, 2008 (Form 10-K for 2008).
*10.5	2004 Incentive Plan (Form 10-Q for the quarter ended June 30, 2004).
	(a) First Amendment to the 2004 Incentive Plan effective February 23, 2007 (Form 10-Q for the quarter ended March 31, 2007).
	(b) Second Amendment to the 2004 Incentive Plan Amendment, effective as of December 31, 2008 (Form 10-K for 2008).
*10.6	2012 Form of Non-Employee Director Restricted Stock Unit Award Agreement (Form 10-K for 2012).
*10.7	Forms of Award Agreements for Executive Officers under 2004 Incentive Plan.
	(a) 2012 Form of Restricted Stock Award Agreement (Form 10-K for 2012).
	(b) 2012 Form of Stock Appreciation Rights Award Agreement (Form 10-K for 2012).
	(c) 2012 Form of Performance Share Award Agreement (Officers) (Form 10-K for 2012).
	(d) 2012 Form of Hybrid Performance Share Award Agreement (Form 10-K for 2012).
	(e) 2012 Form of Performance Share Award Agreement (Employees) (Form 10-K for 2012).
*10.8	2014 Incentive Plan (Form 10-Q for the quarter ended June 30, 2014).
	(a) 2014 Form of Non-Employee Director Restricted Unit Award Agreement (Form 10-Q for the quarter ended June 30, 2014).
	(b) 2015 Form of Restricted Stock Award Agreement (3 year graded) (Form 10-Q for the quarter ended March 31, 2015).
	(c) 2015 Form of Restricted Stock Award Agreement (3 year cliff) (Form 10-Q for the quarter ended March 31, 2015).
	(d) 2015 Form of Performance Share Award Agreement (Officers) (Form 10-Q for the quarter ended March 31, 2015).
	(e) 2015 Form of Hybrid Performance Share Award Agreement (Form 10-Q for the quarter ended March 31, 2015).
	(f) 2015 Form of Performance Share Award Agreement (Employees) (Form 10-Q for the quarter ended March 31, 2015).
10.9	Cabot Oil & Gas Corporation Mineral, Royalty and Overriding Royalty Interest Plan (Registration Statement No. 333-135365).
	(a) Form of Conveyance of Mineral and/or Royalty Interest (Registration Statement No. 333-135365).
	(b) Form of Conveyance of Overriding Royalty Interest (Registration Statement No. 333-135365).
*10.10	Nonemployee Director Deferred Compensation Plan effective December 21, 2012 (Form 10-K for 2012).

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10.11	Amended and Restated Credit Agreement, dated as of September 22, 2010, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, Bank of Montreal, as Documentation Agent, and the Lenders party thereto (Form 10-Q for the quarter ended September 30, 2010).
10.12	First Amendment to Amended and Restated Credit Agreement, dated as of May 4, 2012, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities as Syndication Agent, Bank of Montreal as Documentation Agent, and the Lenders party thereto (Form 10-Q for the quarter ended June 30, 2012).
10.13	Second Amendment to Amended and Restated Credit Agreement, dated as of July 18, 2012, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities and Bank of Montreal as Co-Syndication Agents, BNP Paribas and Wells Fargo as Co-Documentation Agents, and the Lenders party thereto (Form 10-Q for the quarter ended September 30, 2012).
10.14	Third Amendment to Amended and Restated Credit Agreement, dated as of April 17, 2015 (Form 8-K filed on April 23, 2015).
10.15	Fourth Amendment to Amended and Restated Credit Agreement, dated as of December 31, 2015 (Form 8-K filed on February 9, 2016).
10.16	Maximum Credit Amount Increase and Additional Lender Agreement, among the Company, JPMorgan Chase Bank, N.A., Administrative Agent and Toronto Dominion (New York) LLC, Additional Lender, dated as of December 18, 2013 (Form 10-K for 2013).
21.1	Subsidiaries of Cabot Oil & Gas Corporation.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Miller and Lents, Ltd.
31.1	302 Certification—Chairman, President and Chief Executive Officer.
31.2	302 Certification—Vice President and Chief Financial Officer.
32.1	906 Certification.
99.1	Miller and Lents, Ltd. Audit Letter.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

*Compensatory plan, contract or arrangement.

ITEM 16. FORM 10-K SUMMARY

The Company has elected not to include summary information.

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SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on the 1st of March 2018.

CABOT OIL & GAS
CORPORATION

By: /s/ TODD M. ROEMER
Todd M. Roemer
Vice President and Controller