CABOT OIL & GAS CORP
Form 10-K
February 27, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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 |

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, 2014) was approximately $14.2 billion.

As of February 13, 2015, there were 413,170,529 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 23, 2015 are incorporated by reference into Part III of this report.

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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 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," "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

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 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.

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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.
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.
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.
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.
Recompletion. An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.
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.

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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 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 regional offices located in Houston, Texas and Pittsburgh, Pennsylvania.

## STRATEGY

Our objective is to enhance shareholder value over the long-term through consistent growth in cash flows, earnings, production and reserves. We believe this is attainable through a combination of disciplined management and our core asset base that offers a strategic advantage for continued growth. Key components of our business strategy include:

Disciplined Capital Spending Focused on Organic Projects. We allocate our capital program based on projects that we expect will enable us to maximize our production and reserve growth at attractive returns. Our capital program is based on the expectation of being fully funded through operating cash flows, with any shortfalls funded by borrowings under our revolving credit facility. While we consider various growth opportunities, including strategic acquisitions, our primary focus is organic growth through drilling our core areas of operation where we believe we can exploit our extensive inventory of low-cost, repeatable drilling opportunities.

Low Cost Structure. Our operations are focused on select unconventional plays with significant resource potential that allow us to add and produce reserves at a low cost. We have developed sizable, contiguous acreage positions in these core operating areas and believe the concentration of our assets allows us to further reduce costs through economies of scale. We continue to optimize drilling and completion efficiencies through the use of multi-well pad drilling in our core operating areas, resulting in additional cost savings. Furthermore, since we operate in a limited number of geographic areas, we believe we can leverage our technical expertise in these areas to achieve further cost reductions through operational efficiencies. We also operate a majority of our properties, which allows us to more effectively manage all elements of our cost structure.

Conservative Financial Position and Financial Flexibility. We believe the prudent management of our balance sheet and the active management of commodity price risk allows us the financial flexibility to continue to provide consistent production and reserve growth over time, even in periods of depressed commodity prices. We utilize derivative contracts to manage commodity price risk and to provide a level of cash flow predictability. In the event we experience a lower than anticipated commodity price environment, we believe that we have the flexibility to supplement the funding of our capital program with borrowings under our revolving credit facility and select asset sales.

Expand our Unconventional Resource Initiatives. We will continue to evaluate opportunities that generate value and contribute to our growth initiatives, including new exploration concepts and ideas that, if successful, can match the size, scope and rate of returns of our existing core assets. We will also consider the use of joint venture arrangements to achieve these objectives.

## 2015 OUTLOOK

In 2015, we plan to spend approximately $900.0 million on capital and exploration activities. We plan to drill approximately 125 gross wells (or 115.0 net), focusing our capital program in the Marcellus Shale in northeast Pennsylvania and the Eagle Ford Shale in south Texas. We expect to allocate approximately 59% of our 2015 capital program to the Marcellus Shale, approximately 39% to our oil-focused play in the Eagle Ford Shale and the remaining 2% to other emerging plays and non-drilling expenditures. Due to the weak commodity price environment, our overall capital and exploration spending in 2015 is expected to be lower than our expenditures in 2014.

Incremental to our capital and exploration expenditures program, we also expect to contribute approximately $69.8 million to our equity method investments to fund costs associated with the development and construction of two natural gas pipelines in northeast Pennsylvania. 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).

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## DESCRIPTION OF PROPERTIES

Our exploration, development and production operations are primarily concentrated in two unconventional plays—the Marcellus Shale in northeast Pennsylvania and the Eagle Ford Shale in south Texas. We also have operations in various other unconventional and conventional plays throughout the continental United States.

### Marcellus Shale

Our Marcellus Shale properties represent our largest operating and growth area in terms of reserves, production and capital investment. Our properties are principally located in Susquehanna County and to a lesser extent Wyoming County, Pennsylvania. We currently hold approximately 200,000 net acres in the dry gas window of the play. Our 2014 net production in the Marcellus Shale was 479.8 Bcfe, representing approximately 90% of our total equivalent production for the year. As of December 31, 2014, we had a total of 469.0 net wells in the Marcellus Shale, the majority of which are operated by us.

During 2014, we invested $979.5 million in the Marcellus Shale and drilled 114.4 net horizontal wells and turned in line 97.0 net wells. As of December 31, 2014, we had 47.3 net wells that were either in the completion stage or waiting on completion or connection to a pipeline. We exited 2014 with six drilling rigs operating in the play and plan to exit 2015 with three rigs operating.

### 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 89,000 net acres in the oil window of the play. In 2014, our net crude oil/condensate/NGL and natural gas production from the Eagle Ford Shale was 3,799 Mbbl and 1.5 Bcf, respectively, or 24.3 Bcfe, representing approximately 5% of our full year total equivalent production. As of December 31, 2014, we had a total of 167.2 net wells in the Eagle Ford.

During 2014, we invested $542.4 million (excluding acquisitions) in the Eagle Ford Shale and drilled or participated in drilling 61.2 net wells. We also expanded our position in the play with the acquisition of certain proved and unproved properties for cash consideration of approximately $214.7 million. We exited 2014 with four drilling rigs operating in the play and plan to exit 2015 with one rig operating.

### Other Oil and Gas Properties

In addition to our core unconventional resource plays, we also operate or participate in other conventional and unconventional plays throughout the continental United States, including the Utica Shale in Pennsylvania; the Cotton Valley, Haynesville, Bossier, and James Lime formations in east Texas; and the Devonian Shale, Big Lime, Weir and Berea in West Virginia.

### Other Properties

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems, made up of approximately 3,100 miles of pipeline with interconnects to three interstate transmission systems and four local distribution companies and numerous end users as of the end of 2014. The majority of our pipeline infrastructure is located in West Virginia and is regulated by the Federal Energy Regulatory Commission (FERC) for interstate transportation service and the West Virginia Public Service Commission (WVPSC) for intrastate transportation service. As such, the transportation rates and terms of service of our pipeline subsidiary, Cranberry Pipeline Corporation, are subject to the rules and regulations of the FERC and the WVPSC. Our natural gas gathering and transmission pipeline systems in West Virginia enable us to connect new wells quickly and to transport natural gas from the wellhead directly to interstate pipelines, local distribution companies and industrial end users. Control of our gathering and transmission pipeline systems also enables us to purchase, transport and sell natural gas produced by third parties. In addition, we can engage in development drilling without relying upon third parties to transport our natural gas and incur only the incremental costs of pipeline and compressor additions to our system.

We also have two natural gas storage fields located in West Virginia with a combined working capacity of approximately 4 Bcf. We use these storage fields to take advantage of the seasonal variations in the demand for natural gas typically associated with winter natural gas sales, while maintaining production at a nearly constant rate throughout the year. The pipeline systems and storage fields are fully integrated with our operations in West Virginia.

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## 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 approximately $30.5 million, subject to post closing adjustments. Total cash consideration paid as of the closing date was approximately $29.6 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 approximately $210.0 million. Total cash consideration paid as of the closing date was approximately $185.2 million, which reflects the impact of customary purchase price adjustments, an adjustment for consents that the seller was unable to obtain for certain leaseholds prior to closing and acquisition costs.

## DIVESTITURES

In October 2014, we sold certain proved and unproved oil and gas properties in east Texas to a third party for approximately $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 approximately $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 approximately $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 approximately $44.3 million and recognized an aggregate net gain of $19.5 million.

In December 2012, we sold certain proved oil and gas properties located in south Texas to a private company for $29.9 million and recognized an $18.2 million loss on sale of assets.

In June 2012, we sold a 35% non-operated working interest associated with certain of our Pearsall Shale undeveloped leaseholds in south Texas to a wholly-owned subsidiary of Osaka Gas Co., Ltd. for $125.0 million and recognized a $67.0 million gain on sale of assets.

In 2012, we sold various other unproved oil and gas properties and other assets for approximately $14.4 million and recognized an aggregate net gain of $1.8 million.

In 2011, we sold certain proved and unproved oil and gas properties and other assets for approximately $405.5 million and recognized an aggregate net gain of $63.4 million.

In 2010, we various other proved and unproved oil and gas properties and other assets for approximately $182.2 million and recognized an aggregate net gain of $65.6 million.

## MARKETING

Substantially all of our natural gas is sold at market sensitive prices under both long-term and short-term sales contracts. The principal markets for our natural gas are in the northeastern United States and the industrialized Gulf Coast area. In the northeastern United States, we sell natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system. In the Gulf Coast area, we sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Properties in the Gulf Coast area are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

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 systems and interstate pipelines where we have long-term contractual capacity arrangements or through the use of 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 or obtain favorable prices.

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RISK MANAGEMENT

From time to time, we use certain 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 and swap agreements to attempt 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 2014, natural gas collars with floor prices ranging from $3.60 to $4.37 per Mcf and ceiling prices ranging from $4.22 to $4.80 per Mcf covered 336.8 Bcf, or 66%, of our natural gas production at an average price of $4.37 per Mcf. Natural gas swaps covered 102.2 Bcf, or 20%, of our natural gas production at an average price of $4.06 per Mcf. Crude oil swaps covered 612 Mbbl, or 17%, of our crude oil production at an average price $97.00 per Bbl.

As of December 31, 2014, we had the following outstanding commodity derivatives:

| | | | | Collars | | | | Swaps |
|---|---|---|---|---|---|---|---|---|
| | | | | Floor | | Ceiling | | |
| Type of Contract | Volume | | Contract Period | Range | Weighted-Average | Range | Weighted-Average | Weighted-Average |
| Natural gas | 70.9 | Bcf | Jan. 2015 - Dec. 2015 | $3.86 - $3.91 | $3.87 | $4.27 - $4.43 | $4.35 | |
| Natural gas | 70.9 | Bcf | Jan. 2015 - Dec. 2015 | | | | | $3.92 |
| Natural gas | 5.2 | Bcf | Jan. 2015 - Mar. 2015 | | | | | $4.62 |
| Natural gas | 10.4 | Bcf | Apr. 2015 - Oct. 2015 | | | | | $3.86 |

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

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.

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RESERVES

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

| | December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Natural Gas (Bcf) | | | |
| Proved developed reserves | 4,339 | 3,147 | 2,216 |
| Proved undeveloped reserves(1) | 2,743 | 2,148 | 1,480 |
| | 7,082 | 5,295 | 3,696 |
| Crude Oil & NGLs (Mbbl)(2) | | | |
| Proved developed reserves | 27,221 | 13,652 | 12,828 |
| Proved undeveloped reserves(1) | 25,915 | 12,886 | 11,546 |
| | 53,136 | 26,538 | 24,374 |
| Natural gas equivalent (Bcfe)(3) | 7,401 | 5,454 | 3,842 |
| Reserve life index (in years)(4) | 13.9 | 13.2 | 14.4 |

(1) Proved undeveloped reserves for 2014, 2013 and 2012 include reserves drilled but awaiting completion of 501.1 Bcfe, 239.1 Bcfe and 153.3 Bcfe, respectively.

(2) NGL reserves were less than 1.0% of our total proved equivalent reserves for 2014, 2013 and 2012, and 13.5%, 12.3% and 8.7% of our proved crude oil and NGL reserves for 2014, 2013 and 2012, 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, 2014, 2013 and 2012, respectively.

Our proved reserves totaled approximately 7,401 Bcfe at December 31, 2014, of which 96% were natural gas. This reserve level was up by 36% from 5,454 Bcfe at December 31, 2013. In 2014, we added 1,910.6 Bcfe of proved reserves through extensions, discoveries and other additions, primarily due to the positive results from our drilling program in the Dimock field in northeast Pennsylvania. We also had a net upward revision of 493.0 Bcfe, which was primarily due to an upward performance revision of 492.1 Bcfe, primarily in the Dimock field in northeast Pennsylvania and an upward revision of 0.9 Bcfe associated with commodity pricing. In 2014, we produced 531.8 Bcfe and purchased 77.0 Bcfe associated with the acquisitions of oil and gas properties in south Texas.

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 12-month average crude oil and natural gas 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 crude oil and natural gas reserves, including decline curve extrapolations, material balance calculations, 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, the seismic interpretations are not used in the volumetric computation.

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Internal Control

Our Vice President, Engineering and Technology 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 our independent third party engineers. He has a Bachelor of Science degree in Chemical Engineering, specializing in petroleum engineering, and over 32 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 23 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, including the Chairman, President and Chief Executive Officer and Executive Vice President and Chief Financial Officer for approval.

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 February 2, 2015, 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 employed on a contingent fee basis.

Proved Undeveloped Reserves

At December 31, 2014 we had 2,898.3 Bcfe of proved undeveloped (PUD) reserves associated with future development costs of $2.2 billion, which represents an increase of 672.5 Bcfe compared to December 31, 2013. As of December 31, 2014, all proved undeveloped reserves are expected to be developed 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, 2014 |
|---|---|
| Balance at beginning of period | 2,225.8 |
| Transfers to proved developed | (656.0) |
| Additions | 1,031.9 |
| Revision of prior estimates | 230.2 |
| Purchases of reserves in place | 66.4 |
| Balance at end of period | 2,898.3 |

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

- transfer of 656.0 Bcfe from PUD to proved developed reserves based on total capital expenditures of $670.0 million during 2014;
- new PUD reserve additions of 1,031.9 Bcfe primarily in the Dimock field in northeast Pennsylvania;
-

positive PUD reserve revisions of 230.2 Bcfe resulting from positive performance revisions of 222.3 Bcfe, primarily in the Dimock field in northeast Pennsylvania and positive price revisions of 7.9 Bcfe; and

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- purchases of reserves in place of 66.4 Bcfe related to oil and gas properties acquired in the Eagle Ford Shale.

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 contains more than 15% of our total proved reserves.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Production Volumes | | | |
| Natural gas (Bcf) | | | |
| Dimock field | 479.8 | 356.5 | 209.3 |
| Total | 508.0 | 394.2 | 253.2 |
| Oil (Mbbl)[1] | | | |
| Total | 3,961 | 3,221 | 2,407 |
| Equivalents (Bcfe) | | | |
| Dimock field | 479.8 | 356.5 | 209.3 |
| Total | 531.8 | 413.6 | 267.7 |
| Natural Gas Average Sales Price ($/Mcf) | | | |
| Dimock field | $3.42 | $3.48 | $2.82 |
| Total (excluding realized impact of derivative settlements) | $3.41 | $3.43 | $2.79 |
| Total (including realized impact of derivative settlements) | $3.28 | $3.56 | $3.67 |
| Oil Average Sales Price ($/Bbl) | | | |
| Total (excluding realized impact of derivative settlements) | $87.65 | $99.65 | $96.65 |
| Total (including realized impact of derivative settlements) | $88.50 | $101.13 | $101.65 |
| Average Production Costs ($/Mcfe) | | | |
| Dimock field | $0.07 | $0.06 | $0.08 |
| Total | $0.22 | $0.27 | $0.37 |

(1) Includes NGLs which represent less than 1% of our equivalent production for all years presented and 9.4%, 10.5%, and 6.9% of our oil production for the years ended December 31, 2014, 2013 and 2012, 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, in general, 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.

The following table summarizes our gross and net developed and undeveloped leasehold and mineral fee acreage at December 31, 2014.

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Leasehold acreage | 933,418 | 816,343 | 604,724 | 501,691 | 1,538,142 | 1,318,034 |
| Mineral fee acreage | 133,623 | 112,570 | 61,744 | 52,242 | 195,367 | 164,812 |
| Total | 1,067,041 | 928,913 | 666,468 | 553,933 | 1,733,509 | 1,482,846 |

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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, 2014 is 91,697, 68,012 and 87,350 for the years ending December 31, 2015, 2016 and 2017, 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, 2014, approximately 34% of our expiring acreage disclosed above is located in our core 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, 2014. This summary includes natural gas and crude oil wells in which we have a working interest.

| | Gross | Net |
|---|---|---|
| Natural Gas | 4,294 | 3,868.0 |
| Crude Oil | 262 | 205.9 |
| Total[(1)] | 4,556 | 4,073.9 |

(1) Total percentage of gross operated wells is 90.8%.

DRILLING ACTIVITY

We drilled wells or participated in the drilling of wells as indicated in the table below.

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development Wells | | | | | | |
| Productive | 199 | 175.5 | 169 | 145.4 | 149 | 102.7 |
| Dry | — | — | 2 | 1.3 | — | — |
| Extension Wells | | | | | | |
| Productive | — | — | — | — | 8 | 7.0 |
| Dry | — | — | — | — | — | — |
| Exploratory Wells | | | | | | |
| Productive | — | — | 9 | 6.8 | 9 | 6.3 |
| Dry | 1 | 1.0 | 1 | — | 4 | 1.8 |
| Total | 200 | 176.5 | 181 | 153.5 | 170 | 117.8 |
| | | | | | | |
| Acquired Wells | 26 | 23.7 | — | — | — | — |

At December 31, 2014, 17 gross (14.8 net) wells were in the process of being drilled.

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

Competition in our primary producing areas is intense. Price, contract terms 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. We also actively compete against other companies with substantial financial and other resources.

## Major Customers

During the years ended December 31, 2014, 2013 and 2012, two customers accounted for approximately 14% and 10%, four customers accounted for approximately 21%, 16%, 14% and 11% and three customers accounted for approximately 18%, 12% and 10%, 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 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 the FERC’s regulations up to $1,000,000 per day per violation. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties and procedure under its enforcement program.

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Some of our pipelines are subject to regulation by the FERC. We own an intrastate natural gas pipeline through our wholly owned subsidiary, Cranberry Pipeline Corporation, that provides interstate transportation and storage services pursuant to Section 311 of the NGPA, as well as intrastate transportation and storage services that are regulated by the West Virginia Public Service Commission. For qualified intrastate pipelines, FERC allows interstate transportation service "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines without subjecting the intrastate pipeline to the more comprehensive NGA jurisdiction of the FERC. We provide Section 311 service in accordance with a publicly available Statement of Operating Conditions filed with FERC under rates that are subject to approval by the FERC. On December 26, 2012, we filed with the FERC a petition for rate approval of our existing interstate transportation rates and a proposed decrease of our storage rates. By Letter Order issued May 15, 2013, the FERC approved the rate petition.

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 June 12, 2013, the project sponsors filed an application with FERC requesting a certificate of public convenience and necessity to construct and operate the 124 mile pipeline project that, once completed, will provide 650,000 Dth per day of pipeline capacity. On December 2, 2014, the FERC issued a certificate of public convenience and necessity, authorizing the construction and operation of the pipeline project. While FERC has issued the certificate, the project scope or timeline for construction and eventual in-service date may still be impacted by the public regulatory permitting process. If placed into service, the project pipeline will be an interstate pipeline subject to full regulation by FERC under the NGA.

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 currently plans to file an application for a certificate of public convenience and necessity with the FERC during second quarter 2015; however, the timing of that filing is subject to Transco's timely completion of the FERC pre-filing process and, therefore, could change.

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.

We use derivative financial instruments such as collar and 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

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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, the 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 annual 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 2010, 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 2.65% should be the oil pricing index for the five year period beginning July 1, 2011. 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.

Pipeline Safety Regulation

Certain of our pipeline systems and storage fields in West Virginia are regulated for safety compliance by the U.S. Department of Transportation (DOT) and the West Virginia Public Service Commission. In 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (2002 Act), which contains a number of provisions intended to increase pipeline operating safety. The DOT's final regulations implementing the act became effective February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission and non rural gathering pipeline facilities in certain locations within ten years, and at least every seven years thereafter. On March 15, 2006, the DOT revised these regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in non rural areas, and adopt new compliance deadlines. The initial baseline assessments under our integrity management program for our pipeline system in West Virginia were completed in January 2013. Pipeline integrity was confirmed at each of the targeted assessment sites. A new seven year reassessment cycle began during 2013.

In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act), which reauthorized the programs adopted under the 2002 Act, proposed enhancements for state programs to reduce excavation damage to pipelines, established increased federal enforcement of one call excavation programs, and established a new program for review of pipeline security plans and critical facility inspections. Pursuant to the PIPES

Act, the DOT issued regulations on May 5, 2011 that would, with limited exceptions, subject all low stress hazardous liquids pipelines, regardless of location or size, to the DOT's pipeline safety regulations.

In December 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The act increased the maximum civil penalties for pipeline safety administrative enforcement actions; required the DOT to issue regulations requiring the use of automatic or remote controlled shutoff valves on new and rebuilt pipelines and to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure

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safety, and the use of leak detection systems by hazardous liquid pipelines; required pipeline operators to verify their records on maximum allowable operating pressure; and imposed new emergency response and incident notification requirements. The act reflects many of the areas of possible regulatory change described in an Advance Notice of Proposed Rulemaking issued by the DOT on August 18, 2011. Aside from rules contained in the act, which include revisions to DOT's civil penalty authority and the requirement that pipelines verify maximum allowable operating pressure, the DOT has not yet promulgated any new regulations required by the act, although it is anticipated that the DOT will propose new regulations in early 2015. In January 2015, it was announced as part of a broad plan to reduce methane emissions from the oil and natural gas sector that PHMSA will propose pipeline safety standards in 2015 that will result in reduced methane emissions.

On December 3, 2009, the DOT adopted a regulation requiring gas and hazardous liquid pipelines that use supervisory control and data acquisition (SCADA) systems and have at least one controller and control room to develop written control room management procedures by August 1, 2011 and implement the procedures by February 1, 2013. The DOT expedited the program implementation deadline to October 1, 2011 for most of the requirements, except for certain provisions regarding adequate information and alarm management, which had a program implementation deadline of August 1, 2012. We developed and implemented the required control room management procedures in accordance with the deadlines. Effective January 1, 2011, natural gas and hazardous liquid pipelines also became subject to updated reporting requirements with DOT.

The cost of compliance with DOT's integrity management rules depends on integrity testing and the repairs found to be necessary by such testing. Changes to the amount of pipe subject to integrity management, whether by expansion of the definition of the type of areas subject to integrity management procedures or of the applicability of such procedures outside of those defined areas can have a significant impact on costs we may incur to ensure compliance. In the future other laws and regulations may be enacted or adopted or existing laws may be reinterpreted in a manner that could impact our compliance costs. In addition, we may be subject to DOT's enforcement actions and penalties for failure to comply with pipeline regulations.

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. 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

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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.

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 states.

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 gas production, transmission and distribution facilities with a compliance deadline of January 1, 2015. While these rules remain in effect, the EPA announced in 2013 that it would reexamine and reissue the rules over the next three years. The EPA has issued updated rules regarding storage tanks and additional rules are expected. In December 2014, the EPA issued finalized additional amendments to these rules that, among other things, distinguished between multiple flowback stages during completion of hydraulically fractured wells and clarified that storage tanks permanently removed from service are not affected by any requirements. Further, in 2012, seven states sued the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and gas sources is appropriate and, if so, to promulgate performance standards for methane emissions from existing oil and gas sources. In April 2014, the EPA released a set of five white papers analyzing methane emissions from the industry, and, based on responses received, in January 2015 announced plans to propose a rule governing methane emissions from the oil and gas industry in 2015. 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 rock 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 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 gas wells and increased compliance costs, which could 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 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. 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, 2014, we had 691 active employees. 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. The Company and its 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

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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.

ITEM 1A. RISK FACTORS

Natural gas and crude 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 prevailing prices for natural gas and oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets 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. Natural gas prices, based on the first of the month Henry Hub index price, were $4.30 per Mmbtu in December 2014 and have continued to decline to $2.87 per Mmbtu in February 2015, while oil prices, based on the NYMEX monthly average price, were $59.29 per barrel in December 2014 and have continued to decline to $47.33 per barrel in January 2015. Substantial or extended decline in prices in the future would have a negative impact on our oil and gas reserves and financial results. See "Recent commodity price declines have resulted in an impairment of our oil and gas properties, and future natural gas and oil price declines may result in additional write-downs of the carrying amount of our assets, 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 product demand;
- weather conditions;
- political conditions or hostilities in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability 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 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;

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- 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 with any certainty the future prices of natural gas and crude oil. If natural gas and crude oil prices decline significantly for a sustained period of time, the lower prices may cause us to scale back 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 cancelled as a result of a variety of factors beyond our control, including:

- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- decreases in natural gas and oil prices;
- 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 for activity 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 the 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.

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 crude oil and natural gas index prices, 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. 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.

Recent commodity price declines have resulted in an impairment of our oil and gas properties, and future natural gas and oil price declines may result in additional write-downs of the carrying amount of our assets, which could materially and adversely affect our results of operations.

The value of our assets depends on prices of natural gas and 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. For example, in December 2014, we recorded a $771.0 million impairment of oil and gas properties in certain non-core fields, primarily in east Texas. The impairment of these fields was due to a significant decline in commodity prices in late 2014 and management's decision not to pursue any further activity in these non-core areas in the current price environment. 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 crude 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. In the event that commodity prices decline further, there could be a significant revision in the future.

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.

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Our reserve report estimates that production from our proved developed reserves as of December 31, 2014 will increase at a rate of 9% during 2015 and then decline at estimated rates of 36%, 23% and 17% during 2016, 2017 and 2018, 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.

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 2015 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 2015 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. 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. Increased scrutiny of our industry may also occur as a result of EPA's 2014-2016 National Enforcement Initiative, "Ensuring Energy Extraction Activities Comply with Environmental Laws," through which EPA will address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment. In addition, we may be liable for environmental damages caused by previous owners 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 acquire could be difficult, and may divert management's attention away from our existing operations.

The integration of the properties we 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,

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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;
- 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 lessors 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 operation 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. As of December 31, 2014, we owned or operated approximately 3,100 miles of natural gas gathering and pipeline systems. As part of our normal maintenance program, we have identified certain segments of our pipelines that we believe periodically require repair, replacement or additional maintenance.

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

We maintain insurance against some, but not all, of these 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, 2014, non-operated wells represented approximately 9.2% of our total owned gross wells, or approximately 3.2% 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.

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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.

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 certain 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 and swap agreements to attempt to manage price risk more effectively.

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:

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

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

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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, legislation introduced in Congress 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 adopted, 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. Moreover, in May 2014, the EPA announced an Advanced Notice of Proposed Rulemaking under the Toxic Substances Control Act relating to data collection, including the chemical substances and mixtures used in hydraulic fracturing. Further, in May 2013, the Department of the Interior's Bureau of Land Management (BLM) issued a proposed rule to regulate hydraulic fracturing on public and Indian land. The rule would require companies to publicly disclose the chemicals used in hydraulic fracturing operations to the BLM after fracturing operations have been completed and includes provisions addressing well-bore integrity and flowback water management plans. We voluntarily disclose on a well-by-well basis the chemicals we use in the hydraulic fracturing process at www.fracfocus.org.

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 New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants (NESHAPS) to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these final rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells were required to use completion combustion device equipment (i.e., flaring) if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include maximum achievable control technology (MACT) standards for "small" glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves. In December 2014, the EPA finalized additional amendments to these rules that, among other things, distinguished between multiple flowback stages during completion and clarified that storage tanks permanently removed from service are not affected by any requirements. In January 2015, the EPA announced plans to propose a rule in summer 2015 governing methane emissions from oil and natural gas completion operations.

Compliance with these requirements, especially the imposition of these green completion requirements, may require modifications to certain of our operations, 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.

In addition to these federal legislative and regulatory proposals, some states in which we operate, such as Pennsylvania, West Virginia 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, and New York announced the intention to create a statewide ban on hydraulic fracturing in December 2014. In addition, Pennsylvania's Act 13 of 2012 became law on February 14, 2012 and amended the state's Oil and Gas Act to impose an impact fee for drilling, increase setbacks from certain water sources, require water management plans, increase civil penalties, strengthen the Pennsylvania

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Department of Environmental Protection's (PaDEP) authority over the issuance of drilling permits, and require the disclosure of chemical information regarding the components in hydraulic fracturing fluids. On December 19, 2013, the Pennsylvania Supreme Court struck down as unconstitutional portions of Act 13 that made statewide rules on oil and gas preempt local zoning rules. The remaining challenges to Act 13 were remanded to the state commonwealth court, which dismissed those challenges in July 2014. This could result in 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 October 2011, the EPA announced that it plans to develop standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works (POTWs), which will be proposed in 2015. The regulations will be 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. The EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released a progress report outlining work currently underway on December 21, 2012 and is expected to release a draft report of final results in early 2015. 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. For example, in November 2014, the Obama Administration announced an agreement with China to voluntarily reduce GHG emissions to 26% to 28% of 2005 levels by 2025. Further, the United States joined over 190 countries in Lima, Peru in December 2014 and agreed to draft an emissions reduction plan ahead of further international climate negotiations in Paris, France in 2015. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions. For example, in June 2013, the Obama Administration announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas sector. Pursuant to this plan, the EPA announced in January 2015 a plan to regulate methane emissions from the oil and gas sector.

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 CO2e 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.

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

Certain federal income tax law changes have been proposed that, if passed, would have an adverse effect on our financial position, results of operations, and cash flows.

Substantive changes to existing federal income tax laws have been proposed that, if adopted, would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and would impose new taxes. The proposals include: repeal of the percentage depletion allowance for oil and natural gas properties; elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these proposals become law, our taxes will 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 none of these proposals have yet to become law, we do not know the ultimate impact these proposed 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.

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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.

On November 17, 2014, we entered into a Consent Assessment of Civil Penalty with the Pennsylvania Department of Environmental Protection regarding a production fluid spill that resulted from a storage tank fire in Susquehanna County, Pennsylvania. We paid a $120,000 civil penalty with respect to this matter.

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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 19, 2015 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 | 61 | Chairman, President and Chief Executive Officer | 2001 |
| Scott C. Schroeder | 52 | Executive Vice President and Chief Financial Officer | 1997 |
| Jeffrey W. Hutton | 59 | Senior Vice President, Marketing | 1995 |
| G. Kevin Cunningham | 61 | Vice President and General Counsel | 2010 |
| Robert G. Drake | 67 | Vice President, Information Services | 1998 |
| Todd L. Liebl | 57 | Vice President, Land and Business Development | 2012 |
| Steven W. Lindeman | 54 | Vice President, Engineering and Technology | 2011 |
| Phillip L. Stalnaker | 55 | Vice President, Regional Manager North Region | 2009 |
| Matthew P. Kerin | 34 | Treasurer | 2014 |
| Todd M. Roemer | 44 | Controller | 2010 |
| Deidre L. Shearer | 47 | Corporate Secretary and Managing Counsel | 2012 |

All officers are elected annually by our Board of Directors. During 2014, Mr. Scott C. Schroeder was promoted to Executive Vice President and Mr. Jeffrey W. Hutton was promoted to Senior Vice President, Marketing. Prior to this promotion, Mr. Schroeder was Vice President, Chief Financial Officer and Treasurer and Mr. Hutton was Vice President, Marketing. All of the executive officers have been employed by Cabot Oil & Gas Corporation for at least the last five years, except for Mr. Matthew P. Kerin, Mr. Todd M. Roemer and Ms. Deidre L. Shearer.

Mr. Kerin joined the Company in March 2012 and was appointed Treasurer in September 2014. Mr. Kerin most recently served as Manager - Finance and Investor Relations. Prior to joining the Company, Mr. Kerin served as an Associate in the Oil and Gas Investment Banking group at J.P. Morgan Securities. He is a graduate of Texas A&M University with a Bachelor in Business Administration degree in Accounting and a Master of Science degree in Finance. He is also a graduate from the Jones Graduate School of Business at Rice University with a Master in Business Administration degree with a concentration in Finance and Energy.

Mr. Roemer joined the Company in February 2010 and was appointed Controller in March 2010. Prior to joining the Company, Mr. Roemer was in the Energy Practice of PricewaterhouseCoopers LLP from 1996 to February 2010, most recently as an Audit Senior Manager, where he served clients focused on exploration and production. He is a graduate of the University of Houston—Clear Lake with a Bachelor of Science degree in Accounting and is a Certified Public Accountant in the state of Texas.

Ms. Shearer joined the Company in December 2011 and was appointed Corporate Secretary and Managing Counsel in February 2012. Prior to joining the Company, Ms. Shearer was Assistant General Counsel of KBR, Inc. from January 2007, where she was responsible for corporate governance and SEC and NYSE compliance matters. Ms. Shearer received her J.D. degree from The University of Texas School of Law in 1992 and was primarily in private practice until she joined KBR.

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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. A regular dividend has been declared each quarter since we became a public company in 1990.

| | High | Low | Dividends |
|---|---|---|---|
| 2014 | | | |
| First Quarter | $41.54 | $32.18 | $0.02 |
| Second Quarter | $39.33 | $32.35 | $0.02 |
| Third Quarter | $35.16 | $31.41 | $0.02 |
| Fourth Quarter | $34.71 | $28.46 | $0.02 |
| 2013 | | | |
| First Quarter | $34.08 | $23.72 | $0.01 |
| Second Quarter | $36.21 | $31.72 | $0.01 |
| Third Quarter | $39.91 | $34.75 | $0.02 |
| Fourth Quarter | $38.93 | $32.63 | $0.02 |

As of February 2, 2015, there were 408 registered holders of our common stock.

EQUITY COMPENSATION PLAN INFORMATION

On May 1, 2014, our 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 awards may be granted to key employees, consultants and officers. Non-employee directors may be granted discretionary awards under the 2014 Incentive Plan consisting of stock options or stock awards. A total of 18 million shares of common stock may be issued under the 2014 Incentive Plan. Under the 2014 Incentive Plan, no more than 10 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. No additional awards will be granted under any of our 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.

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The following table provides information as of December 31, 2014 regarding the number of shares of common stock that may be issued under our 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 | 3,414,655 | (1) | $12.63 | (2) | 18,044,547 | (3) |
| Equity compensation plans not approved by security holders | n/a | | n/a | | n/a | |
| Total | 3,414,655 | | $12.63 | | 18,044,547 | |

(1) Includes 667,764 SARs to be settled in common stock which become fully vested, if at all, in 2015; 1,088,960 employee performance shares, the performance periods of which end on December 31,2014, 2015 and 2016; 674,787 TSR performance shares, the performance periods of which end on December 31, 2014, 2015 and 2016; 329,061 hybrid performance shares, of which vest, if at all, in 2015, 2016, and 2017; and 604,214 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 667,764 SARs outstanding because all other outstanding awards are issued without an exercise price.

(3) Includes 49,869 shares of restricted stock, the restrictions on which lapse on various dates in 2015, 2016 and 2017; and 17,994,678 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, 2014.

| 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 2014 | 253,700 | $31.91 | 253,700 | 10,107,320 |
| November 2014 | — | — | — | 10,107,320 |
| December 2014 | — | — | — | 10,107,320 |
| Total | 253,700 | | 253,700 | 10,107,320 |

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PERFORMANCE GRAPH

The following graph compares our common stock performance ("COG") with the performance of the Standard & Poors' 500 Stock Index and the Dow Jones U.S. Exploration & Production Index for the period December 2009 through December 2014. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2009 and that all dividends were reinvested.

| | December 31, | | | | | |
|---|---|---|---|---|---|---|
| Calculated Values | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| COG | $100.00 | $87.14 | $175.11 | $229.98 | $359.07 | $274.93 |
| S&P 500 | $100.00 | $115.06 | $117.49 | $136.30 | $180.44 | $205.14 |
| Dow Jones U.S. Exploration & Production | $100.00 | $116.74 | $111.85 | $118.36 | $156.05 | $139.24 |

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) | 2014 | 2013 | 2012 | 2011 | 2010 |
| Statement of Operations Data | | | | | |
| Operating revenues | 2,173,011 | 1,746,278 | 1,204,546 | $979,864 | $863,104 |
| Impairment of oil and gas properties and other assets(1) | 771,037 | — | — | — | 40,903 |
| Gain on sale of assets(2) | 17,120 | 21,351 | 50,635 | 63,382 | 106,294 |
| Income from operations | 106,186 | 551,582 | 306,186 | 306,850 | 266,439 |
| Net income | 104,468 | 279,773 | 131,730 | 122,408 | 103,386 |
| Basic earnings per share | $0.25 | $0.67 | $0.31 | $0.29 | $0.25 |
| Diluted earnings per share | $0.25 | $0.66 | $0.31 | $0.29 | $0.25 |
| Dividends per common share | $0.08 | $0.06 | $0.04 | $0.03 | $0.03 |
| | December 31, | | | | |
| | 2014 | 2013 | 2012 | 2011 | 2010 |
| Balance Sheet Data | | | | | |
| Properties and equipment, net | $4,925,711 | $4,546,227 | $4,310,977 | $3,934,584 | $3,762,760 |
| Total assets | 5,437,716 | 4,981,080 | 4,616,313 | 4,331,493 | 4,005,031 |
| Current portion of long-term debt | — | — | 75,000 | — | — |
| Long-term debt | 1,752,000 | 1,147,000 | 1,012,000 | 950,000 | 975,000 |
| Stockholders' equity | 2,142,733 | 2,204,602 | 2,131,447 | 2,104,768 | 1,872,700 |

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

(2) 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. Gain on sale of assets in 2012 includes a $67.0 million gain from the sale of certain Pearsall Shale undeveloped leaseholds in south Texas and an $18.2 million loss from the sale of certain proved oil and gas properties located in south Texas. Gain on sale of assets in 2011 includes a $34.2 million gain from the sale of certain Haynesville and Bossier Shale oil and gas properties and an aggregate net gain of $29.2 million from the sale of various other properties during the year. Gain on sale of assets in 2010 includes a $49.3 million gain from the sale of our Pennsylvania gathering infrastructure, a $40.7 million gain from the sale of our investment in Tourmaline Oil Corporation and an aggregate net gain of $16.3 million from the sale of various other properties during the year.

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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

On an equivalent basis, our production in 2014 increased by 29% from 2013. We produced 531.8 Bcfe, or 1.5 Bcfe per day, in 2014, compared to 413.6 Bcfe, or 1.1 Bcfe per day, in 2013. Natural gas production increased by 113.8 Bcf, or 29%, to 508.0 Bcf in 2014 compared to 394.2 Bcf in 2013. This increase was primarily the result of higher production in the Marcellus Shale associated with our drilling program in Pennsylvania, partially offset by lower production primarily in Oklahoma and west Texas as a result of certain non-core asset dispositions in the fourth quarter of 2013 and normal production declines in Texas and West Virginia. Crude oil/condensate/NGL production increased by 0.7 Mbbls, or 23%, from 3.2 MMbbls in 2013 to 4.0 MMbbls in 2014. This increase was the result of higher production resulting from our oil-focused Eagle Ford Shale drilling program in south Texas, partially offset by lower production associated with certain non-core asset dispositions in Oklahoma in the fourth quarter of 2013.

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. Our average realized natural gas price for 2014 was $3.28 per Mcf, 8% lower than the $3.56 per Mcf price realized in 2013. Our average realized crude oil price for 2014 was $88.50 per Bbl, 12% lower than the $101.13 per Bbl price realized in 2013. These realized prices include realized gains and losses resulting from commodity derivatives. For information about the impact of these derivatives on realized prices, refer to "Results of Operations" in Item 7.

Commodity prices are determined by many factors that are outside of our control. Historically, commodity prices have been volatile, and we expect them to remain volatile. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases will have on our capital program, production volumes or future revenues. 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. 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.

In December 2014, we recorded a $771.0 million impairment of oil and gas properties in certain non-core fields, primarily in east Texas. The impairment of these fields was due to a significant decline in commodity prices in late 2014 and management's decision not to pursue any further activity in these non-core areas in the current price environment.

Effective April 1, 2014, we elected to discontinue hedge accounting on a prospective basis. Subsequent to April 1, 2014, our derivative instruments were accounted for on a mark-to-market basis with changes in fair value recognized currently in operating revenues in the Consolidated Statement of Operations. As a result of these mark-to-market adjustments, we will likely experience volatility in our earnings from time to time due to commodity price volatility. Refer to “Impact of Derivative Instruments on Operating Revenues” below and Note 6 to the Consolidated Financial Statements for more information.

We drilled 200 gross wells (176.5 net) with a success rate of 99.5% in 2014 compared to 181 gross wells (153.5 net) with a success rate of 98.3% in 2013. Our 2014 total capital and exploration spending was approximately $1.6 billion (excluding the Eagle Ford Shale acquisitions discussed below) compared to $1.2 billion in 2013. The increase in capital spending was the result of our drilling programs in the Marcellus Shale and Eagle Ford Shale. We allocate our planned program for capital and exploration expenditures among our various operating areas based on return expectations, availability of services and human resources.

Our 2015 drilling program includes approximately $900.0 million in capital and exploration expenditures and approximately $69.8 million in expected contributions to our equity method investments. These expenditures are expected to be funded by operating cash flow, existing cash and, if required, borrowings under our revolving credit facility. We will continue to assess the natural gas and crude oil price environment along with our liquidity position and may increase or decrease our capital and exploration expenditures accordingly.

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Acquisitions and Divestitures

In December 2014, we completed the acquisition of certain proved and unproved oil and gas properties in the Eagle Ford Shale in south Texas for approximately $30.5 million and paid total cash consideration as of the closing date of approximately $29.6 million, which reflects the impact of customary purchase price adjustments and acquisition costs. The acquisition was funded with borrowings under our revolving credit facility.

In October 2014, we completed the acquisition of certain proved and unproved oil and gas properties in the Eagle Ford Shale in south Texas for approximately $210.0 million and paid total net cash consideration as of the closing date of approximately $185.2 million, which reflects the purchase price and adjustments of approximately $17.4 million for consents that the seller was unable to obtain for certain leaseholds prior to closing and approximately $8.0 million for the impact of customary purchase price adjustments and acquisition costs. The acquisition was funded with proceeds from the private placement of senior unsecured fixed rate notes completed in September 2014.

In October 2014, we completed the divestiture of certain proved and unproved oil and gas properties in east Texas to a third party for approximately $44.3 million. Total cash consideration received by the Company as of the closing date was approximately $42.8 million, which reflects the impact of customary purchase price adjustments.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2014 were from funds generated from the sale of natural gas and oil production, the issuance of fixed rate notes and proceeds from the sale of certain oil and gas properties during the year. These cash flows were primarily used to fund our capital and exploration expenditures, repayments of borrowings under our revolving credit facility and related interest payments, share repurchases and the payment of dividends. See below for additional discussion and analysis of cash flow.

Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes and operating expenses. Prices for natural gas and crude oil have historically been volatile, including seasonal influences and demand; however, the impact of other risks and uncertainties have also influenced prices throughout the recent years. In addition, fluctuations in cash flow may result in an increase or decrease in our capital and exploration expenditures. See "Results of Operations" for a review of the impact of prices and volumes on revenues.

Our working capital is also substantially influenced by the variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. We believe we have adequate availability under our revolving credit facility and liquidity available to meet our working capital requirements.

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Cash flows provided by operating activities | $1,236,435 | $1,024,526 | $652,093 |
| Cash flows used in investing activities | (1,664,840) | (918,207) | (765,514) |
| Cash flows provided by (used in) financing activities | 425,959 | (113,655) | 114,246 |
| Net increase (decrease) in cash and cash equivalents | $(2,446) | $(7,336) | $825 |

Operating Activities. Net cash provided by operating activities in 2014 increased by $211.9 million over 2013. This increase was primarily due to higher operating revenues, partially offset by higher operating expenses (excluding non-cash expenses) and an increase in working capital. The increase in operating revenues was primarily due to an increase in equivalent production, partially offset by a decrease in realized natural gas and crude oil prices. Equivalent production volumes increased by 29% for 2014 compared to 2013 as a result of higher natural gas and oil production. Average realized natural gas and crude oil prices decreased by 8% and 12%, respectively, for 2014 compared to 2013.

Net cash provided by operating activities in 2013 increased by $372.4 million over 2012. 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 equivalent production, partially offset by lower realized natural gas and crude oil prices. Equivalent production volumes increased by 55% for 2013 compared to 2012 as a result of higher natural gas and crude oil production. Average realized natural gas and crude oil prices decreased by 3% and less than 1%, respectively, for 2013 compared to 2012.

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See "Results of Operations" for additional information relative to commodity price, production and operating expense movements. 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. Realized prices may decline in future periods.

Investing Activities. Cash flows used in investing activities increased by $746.6 million from 2013 to 2014 due to a $284.9 million increase in capital and exploration expenditures, a decrease of $284.0 million in proceeds from the sale of assets, a $214.7 million increase in acquisition expenditures related to the acquisitions of Eagle Ford Shale assets that closed in the fourth quarter of 2014, and a $19.2 million increase in capital contributions associated with our equity investments. Partially offsetting the increases was a $56.2 million decrease in restricted cash related to the release of funds by our qualified intermediary due to a lapse in the statutory holding period and the funding of oil and gas lease acquisitions during 2014 associated with like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code.

Cash flows used in investing activities increased by $152.7 million from 2012 to 2013 due to a $266.8 million increase in capital and exploration expenditures and a $12.0 million increase associated with our equity investment in Constitution. These increases were partially offset by a net $126.1 million increase in proceeds from the sale of assets, a portion of which was retained in a qualified intermediary and recognized as restricted cash on the Consolidated Balance Sheet.

Financing Activities. Cash flows provided by financing activities increased by $539.6 million from 2013 to 2014 due to $545.0 million of higher net borrowings and a decrease in share repurchases of $25.8 million, partially offset by a decrease of $20.3 million in tax benefits associated with our stock-based compensation, an $8.0 million increase in dividends paid and an increase in cash paid for capitalized debt issuance costs of $2.9 million.

Cash flows used in financing activities increased by $227.9 million from 2012 to 2013 due to $164.6 million of stock repurchases, $77.0 million of lower net borrowings and an increase in dividends paid of $8.5 million, partially offset by an $18.9 million increase in the tax benefit associated with our stock based compensation and a decrease in cash paid for capitalized debt issuance costs of $2.3 million.

In September 2014, we completed a private placement of $925 million aggregate principal amount of senior unsecured fixed rate notes with a weighted-average interest rate of 3.65%, consisting of amounts due in 2021, 2024 and 2026.

Effective April 15, 2014, the lenders under our revolving credit facility approved an increase in our borrowing base from $2.3 billion to $3.1 billion as part of the annual redetermination under the terms of the revolving credit facility agreement. The commitments under the revolving credit facility remain unchanged at $1.4 billion. See Note 5 of the Notes to the Consolidated Financial Statements for further details.

At December 31, 2014, we had $140.0 million of borrowings outstanding under our revolving credit facility at a weighted-average interest rate of 2.4% compared to $460.0 million of borrowings outstanding at a weighted-average interest rate of 2.0% at December 31, 2013. As of December 31, 2014, we had $1.3 billion available for future borrowings under our revolving credit facility.

We were in compliance with all restrictive financial covenants in both the revolving credit facility and fixed rate notes as of December 31, 2014.

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. Management believes that, with internally generated cash flow, existing cash on hand and availability under our revolving credit facility, we have the capacity to finance our spending plans and maintain our strong financial position.

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Capitalization

Information about our capitalization is as follows:

| (Dollars in thousands) | December 31, 2014 | 2013 |
|---|---|---|
| Debt[(1)] | $1,752,000 | $1,147,000 |
| Stockholders' equity | 2,142,733 | 2,204,602 |
| Total capitalization | $3,894,733 | $3,351,602 |
| Debt to capitalization | 45 % | 34 % |
| Cash and cash equivalents | $20,954 | $23,400 |

(1) Includes $140.0 million and $460.0 million of borrowings outstanding under our revolving credit facility at December 31, 2014 and 2013, respectively.

For the years ended December 31, 2014 and 2013, we repurchased 4.3 million shares for a total cost of $138.9 million and 4.8 million shares for a total cost of $164.6 million, respectively. During 2014 and 2013, we also paid dividends of $33.3 million ($0.08 per share) and $25.2 million ($0.06 per share) on our common stock, respectively. A regular dividend has been declared for each quarter since we became a public company in 1990.

Capital and Exploration Expenditures

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

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

| (In thousands) | Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Capital Expenditures | | | |
| Drilling and facilities | $1,454,288 | $1,096,705 | $843,528 |
| Leasehold acquisitions | 73,962 | 71,106 | 88,880 |
| Property acquisitions | 214,737 | 128 | — |
| Pipeline and gathering | 1,287 | 1,222 | 94 |
| Other | 14,791 | 8,816 | 8,547 |
| | 1,759,065 | 1,177,977 | 941,049 |
| Exploration expense | 28,746 | 18,165 | 37,476 |
| Total | $1,787,811 | $1,196,142 | $978,525 |

We plan to drill approximately 125 gross wells (or 115.0 net) in 2015 compared to 200 gross wells (176.5 net) drilled in 2014. In 2015, we plan to spend approximately $900.0 million in total capital and exploration expenditures, compared to $1.6 billion (excluding property acquisitions of $214.7 million, as discussed in Note 2 to the Consolidated Financial Statements) in 2014. Due to the weak commodity price environment, our overall capital and exploration spending in 2015 is expected to be lower than our expenditures in 2014. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease our capital and exploration expenditures accordingly.

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Contractual Obligations

A summary of our contractual obligations as of December 31, 2014 are set forth in the following table:

| | | Payments Due by Year | | | |
|---|---|---|---|---|---|
| (In thousands) | Total | 2015 | 2016 to 2017 | 2018 to 2019 | 2020 & Beyond |
| Long-term debt | $1,752,000 | $— | $160,000 | $312,000 | $1,280,000 |
| Interest on long-term debt(1) | 590,597 | 82,595 | 160,842 | 125,375 | 221,785 |
| Transportation and gathering agreements(2) | 1,950,612 | 130,411 | 325,248 | 268,162 | 1,226,791 |
| Drilling rig commitments(2) | 21,428 | 14,399 | 7,029 | — | — |
| Operating leases(2) | 25,813 | 5,818 | 6,342 | 4,189 | 9,464 |
| Equity investment contribution commitments(3) | 275,002 | 69,833 | 194,825 | 10,344 | — |
| Total contractual obligations | $4,615,452 | $303,056 | $854,286 | $720,070 | $2,738,040 |

(1) Interest payments have been calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2014. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2014 outstanding balance of $140.0 million will be outstanding through the May 2017 maturity date and that our fixed rate notes will remain outstanding through their respective maturity dates. A constant interest rate of 2.4% was assumed for the interest payments on our revolving credit facility, which was the December 31, 2014 weighted-average interest rate. Actual results will differ from these estimates and assumptions.

(2) In January 2015, we entered into a natural gas transportation agreement associated with our production in Pennsylvania, which increased our future aggregate obligations under our transportation commitments by approximately $105.9 million over the next 10 years, which is not included in the table above. For further information on our obligations under transportation and gathering agreements, drilling rig commitments and operating leases, see Note 9 of the Notes to the Consolidated Financial Statements.

(3) For further information on our equity investment contribution commitment, 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, 2014 was $126.7 million. 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.

Potential Impact of Our Critical Accounting Policies

Readers of this document and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. Our most significant policies are discussed below.

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. 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 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 crude oil and natural gas 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.

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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 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 $0.05 per Mcfe and an increase of $0.05 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 $0.05 per Mcfe and an increase of $0.07 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 remain low or decline, there could be a significant revision in the future. 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 $21.8 million or decrease by approximately $14.8 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 and to a lesser extent meter stations, pipelines, processing plants and compressors. 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.

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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.

Through March 31, 2014, we elected to designate our commodity derivatives as cash flow hedges for accounting purposes. Effective April 1, 2014, we elected to discontinue hedge accounting for our commodity derivatives on a prospective basis. Accordingly, the change in the fair value of derivatives designated as cash flow hedges that were effective was recorded to accumulated other comprehensive income (loss) in stockholders' equity in the Consolidated Balance Sheet. The ineffective portion of the change in the fair value of derivatives designated as cash flow hedges and the change in fair value of derivatives not designated as hedges 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. Such quotes 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 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.

Employee Benefit Plans

Our costs of long-term employee benefits, particularly postretirement benefits, are incurred over long periods of time, and involve many uncertainties over those periods. The net periodic benefit cost attributable to current periods is based on several assumptions about such future uncertainties, and is sensitive to changes in those assumptions. It is management's responsibility, often with the assistance of independent experts, to select assumptions that in its judgment represent best estimates of those uncertainties. It also is management's responsibility to review those assumptions periodically to reflect changes in economic or other factors that affect those assumptions. Significant assumptions used to determine our postretirement benefit obligation and related costs include discount rates and health care cost trends. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion relative to our employee benefit plans.

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.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The guidance applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date. The guidance is effective for interim and annual periods beginning on or after December 15, 2014. We do not expect the adoption of this guidance to have a material impact on our financial position, results of operations or cash flows.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, as a new Topic, Accounting Standards Codification 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. This ASU is effective beginning in fiscal year 2017 and can be adopted either retrospectively or as a cumulative-effect adjustment as of the date of adoption. We are currently evaluating the effect that adopting this guidance will have on our financial position, results of operations or cash flows.

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In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern, as a new Sub-topic, Accounting Standards Codification Sub-topic 205.40. The new going concern standard codifies in generally accepted accounting principles (GAAP) management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. This ASU is effective for interim and annual periods beginning on or after December 15, 2016 and early adoption is permitted. We do not expect the adoption of this guidance to have a material impact on our financial position or results of operations.

## OTHER ISSUES AND CONTINGENCIES

Regulations. Our operations are subject to various types of regulation by federal, state and local authorities. See "Regulation of Oil and Natural Gas Exploration and Production," "Natural Gas Marketing, Gathering and Transportation," "Federal Regulation of Petroleum," "Pipeline Safety Regulation," and "Environmental and Safety Regulations" in 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 revolving credit agreement and our fixed rate notes 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 plus adjusted cash to indebtedness and other liabilities of 1.75 to 1.0. Our revolving credit agreement also requires us to maintain a minimum current ratio of 1.0 to 1.0. At December 31, 2014, we were in compliance with all restrictive financial covenants in both the revolving credit agreement and fixed rate notes. In the unforeseen event that we fail to comply with these covenants, we may apply for a temporary waiver with the lender, which, if granted, would allow us a period of time to remedy the situation.

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 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. 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 and markets 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 long-lived assets. 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. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. However, management may mitigate this price risk on all or a portion of our anticipated production with the use of commodity derivatives. Most recently, we have used commodity derivatives such as collar and swap arrangements to reduce the impact of declining prices 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

### 2014 and 2013 Compared

We reported net income for 2014 of $104.5 million, or $0.25 per share, compared to net income for 2013 of $279.8 million, or $0.67 per share. The decrease in net income was due to higher operating expenses, partially offset by an increase in operating revenues and an increase in 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) | 2014 | 2013 | Amount | Percent |
| Natural gas | $1,590,625 | $1,405,262 | $185,363 | 13 % |
| Crude oil and condensate | 313,889 | 291,418 | 22,471 | 8 % |
| Gain (loss) on derivative instruments | 219,319 | — | 219,319 | 100 % |
| Brokered natural gas | 34,416 | 36,450 | (2,034) | (6)% |
| Other | 14,762 | 13,148 | 1,614 | 12 % |
| | $2,173,011 | $1,746,278 | $426,733 | 24 % |

| | Year Ended December 31, | | Variance | | Increase (Decrease) |
|---|---|---|---|---|---|
| | 2014 | 2013 | Amount | Percent | (In thousands) |
| Price Variances | | | | | |
| Natural gas[(1)] | $3.13 | $3.56 | $(0.43) | (12)% | $(220,273) |
| Crude oil and condensate[(2)] | $87.48 | $101.13 | $(13.65) | (13)% | (48,973) |
| Total | | | | | $(269,246) |
| Volume Variances | | | | | |
| Natural gas (Bcf) | 508.0 | 394.2 | 113.8 | 29 % | $405,636 |
| Crude oil and condensate (Mbbl) | 3,588 | 2,882 | 706 | 24 % | 71,444 |
| Total | | | | | $477,080 |

(1) These prices include the realized impact of cash flow hedge settlements, which decreased the price by $0.28 per Mcf in 2014 and increased the price by $0.13 per Mcf in 2013.

(2) These prices include the realized impact of cash flow hedge settlements, which decreased the price by $0.17 per Bbl in 2014 and increased the price by $1.48 per Bbl in 2013.

Natural Gas Revenues

The increase in natural gas revenues of $185.4 million is due to higher production, partially offset by lower natural gas prices. The increase in our production was the result of our Marcellus Shale drilling program in Pennsylvania, partially offset by lower production primarily in Oklahoma and west Texas as a result of certain non-core asset dispositions in the fourth quarter of 2013 and normal production declines in Texas and West Virginia.

Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $22.5 million is due to higher production, partially offset by lower crude oil prices. The increase in production was a result of our oil-focused Eagle Ford Shale drilling program in south Texas, partially offset by lower production associated with certain non-core asset dispositions in Oklahoma and west Texas in the fourth quarter of 2013.

Gain (Loss) on Derivative Instruments

Effective April 1, 2014, we elected to discontinue hedge accounting on a prospective basis. Subsequent to April 1, 2014, our derivative instruments were accounted for on a mark-to-market basis with changes in fair value recognized currently in operating revenues in the Consolidated Statement of Operations. Gain (loss) on derivative instruments includes an $81.7 million gain related to the change in fair value of realized cash settlements of derivative instruments previously frozen in accumulated other comprehensive income (loss) and a $137.6 million unrealized mark-to-market gain on our commodity derivative instruments.

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Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized and unrealized gain (loss) of our derivative instruments:

| (In thousands) | Year Ended December 31, 2014 | 2013 |
|---|---|---|
| Realized | | |
| Natural gas | $(143,577) | $52,733 |
| Crude oil and condensate | (626) | 4,269 |
| Gain (loss) on derivative instruments | 81,716 | — |
| | $(62,487) | $57,002 |
| Unrealized | | |
| Gain (loss) on derivative instruments | 137,603 | — |
| | $75,116 | $57,002 |

Brokered Natural Gas

| | Year Ended December 31, 2014 | 2013 | Amount | Percent | Price and Volume Variances (In thousands) |
|---|---|---|---|---|---|
| Brokered Natural Gas Sales | | | | | |
| Sales price ($/Mcf) | $ 4.65 | $ 4.11 | $0.54 | 13 % | $3,997 |
| Volume brokered (Mmcf) | x 7,402 | x 8,874 | (1,472) | (17)% | (6,031) |
| Brokered natural gas (In thousands) | $ 34,416 | $ 36,450 | | | $(2,034) |
| Brokered Natural Gas Purchases | | | | | |
| Purchase price ($/Mcf) | $ 4.06 | $ 3.37 | $0.69 | 20 % | $(5,134) |
| Volume brokered (Mmcf) | x 7,402 | x 8,874 | (1,472) | (17)% | 5,040 |
| Brokered natural gas (In thousands) | $ 30,030 | $ 29,936 | | | $(94) |
| Brokered natural gas margin (In thousands) | $ 4,386 | $ 6,514 | | | $(2,128) |

The $2.1 million decrease in brokered natural gas margin is a result of lower brokered volumes and an increase in purchase price that outpaced the increase in sales price.

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Operating and Other Expenses

| (In thousands) | Year Ended December 31, 2014 | 2013 | Variance Amount | Percent |
|---|---|---|---|---|
| Operating and Other Expenses | | | | |
| Direct operations | $145,529 | $140,856 | $4,673 | 3 % |
| Transportation and gathering | 349,321 | 229,489 | 119,832 | 52 % |
| Brokered natural gas | 30,030 | 29,936 | 94 | — % |
| Taxes other than income | 47,012 | 43,045 | 3,967 | 9 % |
| Exploration | 28,746 | 18,165 | 10,581 | 58 % |
| Depreciation, depletion and amortization | 632,760 | 651,052 | (18,292) | (3)% |
| Impairment of oil and gas properties | 771,037 | — | 771,037 | 100 % |
| General and administrative | 82,590 | 104,606 | (22,016) | (21)% |
| Total operating expense | $2,087,025 | $1,217,149 | $869,876 | 71 % |
| | | | | |
| Earnings (loss) on equity method investments | $3,080 | $1,102 | $1,978 | 179 % |
| Gain (loss) on sale of assets | 17,120 | 21,351 | (4,231) | (20)% |
| Interest expense | 73,785 | 66,044 | 7,741 | 12 % |
| Income tax (benefit) expense | (72,067) | 205,765 | (277,832) | (135)% |

Total costs and expenses from operations increased by $869.9 million from 2013 to 2014. The primary reasons for this fluctuation are as follows:

- Direct operations increased $4.7 million largely due to higher operating costs as a result of higher production, an increase in disposal and recycling costs related to our Marcellus Shale operations and an increase in costs associated with oil processing and related fuel charges related to our Eagle Ford Shale operations. Partially offsetting these increases were lower costs associated with certain non-core assets in Oklahoma and west Texas that were sold in the fourth quarter of 2013.
- Transportation and gathering increased $119.8 million due to higher throughput as a result of higher production, slightly higher transportation rates and the commencement of various transportation and gathering agreements in late 2013 and during 2014.
- Brokered natural gas increased $0.1 million from 2013 to 2014. See the preceding table titled "Brokered Natural Gas" for further analysis.
- Taxes other than income increased $4.0 million due to $2.5 million higher drilling impact fees associated with our Marcellus Shale drilling activities, $2.5 million higher production taxes and $0.9 million higher franchise and other taxes. Production taxes increased due to higher oil production in south Texas, offset by taxes associated with certain non-core assets in Oklahoma and west Texas that were sold in the fourth quarter of 2013. These increases are partially offset by a $1.9 million decrease in ad valorem taxes.
- Exploration increased $10.6 million as a result of higher exploratory dry hole costs of $7.5 million and higher geophysical and geological and other expenses.
- Depreciation, depletion and amortization decreased $18.3 million due to a $36.2 million decrease in amortization of unproved properties in 2014 due to lower amortization rates as a result of favorable results from our drilling program in Pennsylvania. This decrease was partially offset by a net increase in depreciation and depletion of $14.6 million, consisting of a $167.6 million increase due to higher equivalent production volumes for 2014 compared to 2013, partially offset by a decrease of $153.0 million due to a lower DD&A rate of $1.13 per Mcfe for 2014 compared to $1.42 per Mcfe for 2013. The lower DD&A rate was primarily due to lower cost of reserve additions associated with our Marcellus Shale drilling program and the impact of the disposition of higher rate fields in Oklahoma and west Texas in the fourth quarter of 2013.
- Impairment of oil and gas properties was $771.0 million in 2014 due to the impairment of certain non-core fields, primarily in east Texas. The impairment of these fields was due to a significant decline in commodity prices in late

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2014 and management's decision not to pursue activity in these non-core areas in the current price environment. There was no impairment in 2013.

- General and administrative decreased $22.0 million due to lower stock-based compensation expense of $30.4 million associated with the mark-to-market of our liability-based performance awards and our supplemental employee incentive plan due to changes in our stock price during 2014 compared to 2013 and lower employee-related expenses. These decreases were partially offset by increases in professional fees.

Earnings (loss) on equity method investments. The increase in equity method investments is the result of the increase in our proportionate share of net earnings from our equity method investments in 2014 compared to 2013.

Gain (Loss) on Sale of Assets. During 2014, we recognized an aggregate gain of $17.1 million primarily due to the sale of certain proved and unproved oil and gas properties in east Texas. During 2013, we recognized an aggregate net gain of $21.4 million, which 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. We also sold various other proved and unproved properties in 2013 for a net gain of $19.5 million.

Interest Expense. Interest expense increased $7.7 million as a result of an increase in interest expense of $9.7 million associated with our private placement in September 2014 of $925 million aggregate principal amount of senior unsecured fixed rate notes with a weighted-average interest rate of 3.65%, higher commitment fees of $2.3 million and increased amortization of debt issuance costs of $1.1 million. These increases were partially offset by a decrease in interest expense of $3.1 million due to the repayment of $75.0 million of our 7.33% weighted-average fixed rate notes in July 2013 and $1.1 million associated with our revolving credit facility due to a decrease in weighted-average borrowings based on daily balances of approximately $410.0 million compared to approximately $454.4 million during 2014 and 2013, respectively.

Income Tax Expense. Income tax expense decreased $277.8 million due to a decrease in pretax income and a lower effective tax rate. The effective tax rates for 2014 and 2013 were (222.4)% and 42.4%, respectively. The effective tax rate was lower as a result of a change in estimated net deferred state tax liabilities reflected in our Consolidated Balance Sheet, which were based on updated state apportionment factors in states in which we operate.

2013 and 2012 Compared

We reported net income for 2013 of $279.8 million, or $0.67 per share, compared to net income for 2012 of $131.7 million, or $0.31 per share. The increase in net income was primarily due to an increase in natural gas and crude oil and condensate revenues, partially offset higher operating expenses.

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) | 2013 | 2012 | Amount | Percent |
| Natural gas | $1,405,262 | $934,134 | $471,128 | 50 % |
| Crude oil and condensate | 291,418 | 227,933 | 63,485 | 28 % |
| Gain (loss) on derivative instruments | — | (494 ) | 494 | 100 % |
| Brokered natural gas | 36,450 | 34,005 | 2,445 | 7 % |
| Other | 13,148 | 8,968 | 4,180 | 47 % |
| | $1,746,278 | $1,204,546 | $541,732 | 45 % |

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| | Year Ended December 31, | | Variance | | Increase (Decrease) |
|---|---|---|---|---|---|
| | 2013 | 2012 | Amount | Percent | (In thousands) |
| Price Variances | | | | | |
| Natural gas[1] | $3.56 | $3.67 | $(0.11) | (3)% | $(43,290) |
| Crude oil and condensate[2] | $101.13 | $101.65 | $(0.52) | (1)% | (1,571) |
| Total | | | | | $(44,861) |
| Volume Variances | | | | | |
| Natural gas (Bcf) | 394.2 | 253.2 | 141.0 | 56% | $514,418 |
| Crude oil and condensate (Mbbl) | 2,882 | 2,242 | 640 | 29% | 65,056 |
| Total | | | | | $579,474 |

(1) These prices include the realized impact of cash flow hedge settlements, which increased the price by $0.13 per Mcf in 2013 and $0.89 per Mcf in 2012.

(2) These prices include the realized impact of cash flow hedge settlements, which increased the price by $1.48 per Bbl in 2013 and $5.00 per Bbl in 2012.

Natural Gas Revenues

The increase in natural gas revenues of $471.1 million is due to higher production, partially offset by lower natural gas prices. The increase in our production was the result of our Marcellus Shale drilling program in Pennsylvania and expanded infrastructure in the area, partially offset by lower production primarily in Texas, Oklahoma and West Virginia due to reduced natural gas drilling in these areas and normal production declines.

Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $63.5 million is due to higher production associated with our oil focused Eagle Ford Shale drilling program in south Texas and, to a lesser extent, Oklahoma, partially offset by lower crude oil prices.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized and unrealized gain (loss) of our derivative instruments:

| | Year Ended December 31, | |
|---|---|---|
| (In thousands) | 2013 | 2012 |
| Realized | | |
| Natural gas | $52,733 | $225,108 |
| Crude oil and condensate | 4,269 | 11,218 |
| | $57,002 | $236,326 |
| Unrealized | | |
| Gain (loss) on derivative instruments | — | (494) |
| | $57,002 | $235,832 |

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Brokered Natural Gas

| | Year Ended December 31, | | Variance | | Price and Volume Variances (In thousands) |
|---|---|---|---|---|---|
| | 2013 | 2012 | Amount | Percent | |
| Brokered Natural Gas Sales | | | | | |
| Sales price ($/Mcf) | $ 4.11 | $ 3.57 | $0.54 | 15 % | $4,776 |
| Volume brokered (Mmcf) | x 8,874 | x 9,527 | (653 ) | (7 )% | (2,331 ) |
| Brokered natural gas (In thousands) | $ 36,450 | $ 34,005 | | | $2,445 |
| Brokered Natural Gas Purchases | | | | | |
| Purchase price ($/Mcf) | $ 3.37 | $ 2.99 | $0.38 | 13 % | $(3,388 ) |
| Volume brokered (Mmcf) | x 8,874 | x 9,527 | (653 ) | (7 )% | 1,954 |
| Brokered natural gas (In thousands) | $ 29,936 | $ 28,502 | | | $(1,434 ) |
| Brokered natural gas margin (In thousands) | $ 6,514 | $ 5,503 | | | $1,011 |

The $1.0 million increase in brokered natural gas margin is a result of an increase in sales price that outpaced the increase in purchase price partially offset by a decrease in brokered volumes.

Operating and Other Expenses

| | Year Ended December 31, | | Variance | |
|---|---|---|---|---|
| (In thousands) | 2013 | 2012 | Amount | Percent |
| Operating and Other Expenses | | | | |
| Direct operations | $140,856 | $118,243 | $22,613 | 19 % |
| Transportation and gathering | 229,489 | 143,309 | 86,180 | 60 % |
| Brokered natural gas | 29,936 | 28,502 | 1,434 | 5 % |
| Taxes other than income | 43,045 | 48,874 | (5,829 ) | (12 )% |
| Exploration | 18,165 | 37,476 | (19,311 ) | (52 )% |
| Depreciation, depletion and amortization | 651,052 | 451,405 | 199,647 | 44 % |
| General and administrative | 104,606 | 121,239 | (16,633 ) | (14 )% |
| Total operating expense | $1,217,149 | $949,048 | $268,101 | 28 % |
| | | | | |
| Earnings (loss) on equity method investments | $1,102 | $53 | $1,049 | 1,979 % |
| Gain (loss) on sale of assets | 21,351 | 50,635 | (29,284 ) | (58 )% |
| Interest expense | 66,044 | 68,346 | (2,302 ) | (3 )% |
| Income tax expense | 205,765 | 106,110 | 99,655 | 94 % |

Total costs and expenses from operations increased by $268.1 million from 2012 to 2013. The primary reasons for this fluctuation are as follows:

- Direct operations increased $22.6 million largely due to higher operating costs primarily driven by higher production. In addition, we experienced higher costs associated with oil separation and processing and related fuel charges as a result of more stringent oil pipeline quality requirements in south Texas related to our Eagle Ford operations, higher plugging and abandonment costs primarily in east Texas and higher environmental and regulatory costs. Partially offsetting these increases were a decrease in workover activity and lower lease maintenance costs.
- Transportation and gathering increased $86.2 million due to higher throughput as a result of higher production, slightly higher transportation rates and the commencement of various transportation and gathering agreements primarily in northeast Pennsylvania and south Texas throughout the second half of 2012.
- Brokered natural gas increased $1.4 million from 2012 to 2013. See the preceding table titled “Brokered Natural Gas” for further analysis.

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- Taxes other than income decreased $5.8 million due to lower drilling impact fees associated with our Marcellus Shale drilling activities. Full year 2012 included $8.3 million related to the initial assessment of drilling impact fees associated with 2011 and prior period wells. In addition, franchise, sales and use and ad valorem taxes decreased year over year. These decreases were partially offset by higher production taxes as a result of an increase in oil production in south Texas.
- Exploration decreased $19.3 million due to lower exploratory dry hole costs of $13.6 million primarily due to our Brown Dense/Smackover exploratory well in Union County, Arkansas that was recorded in 2012. There were no significant exploratory dry hole costs recorded in 2013. In addition, geophysical and geological expenses decreased $7.0 million due to fewer requirements for the acquisition and processing of seismic data.
- Depreciation, depletion and amortization increased $199.6 million, of which $234.4 million was due to higher equivalent production volumes for 2013 compared to 2012, partially offset by a decrease of $70.8 million due to a lower DD&A rate of $1.42 per Mcfe for 2013 compared to $1.58 per Mcfe for 2012. The lower DD&A rate was primarily due to lower cost of reserve additions associated with our 2013 and 2012 drilling programs. In addition, amortization of unproved properties increased $35.5 million primarily due to an increase in amortization rates as a result of our ongoing evaluation of our unproved properties and undeveloped leasehold acquisitions during the year.
- General and administrative decreased $16.6 million due to lower pension expense of $19.5 million associated with the liquidation of our pension plan that occurred in the second quarter of 2012, a decrease in legal expenses of $9.0 million and $2.2 million of lower charitable contribution costs associated with the funding of the construction of a hospital in northeast Pennsylvania in 2012. These decreases are partially offset by $18.3 million of higher stock based compensation expense associated with the mark to market of our liability based performance awards due to changes in our stock price during 2013 compared to 2012 and the achievement of the interim and final triggers of our supplemental incentive compensation plan during 2013.

Gain (Loss) on Sale of Assets. During 2013, we recognized an aggregate net gain of $21.4 million, which 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. We also sold various other proved and unproved properties for a net gain of $19.5 million. During 2012, we recognized an aggregate net gain of $50.6 million, which includes a $67.0 million gain associated with the sale of certain of our Pearsall Shale undeveloped leaseholds in south Texas, partially offset by an $18.2 million loss on the sale of certain proved oil and gas properties located in south Texas.

Interest Expense. Interest expense decreased $2.3 million as a result lower debt extinguishment costs of $1.3 million associated with our revolving credit facility amendment in May 2012 and lower interest expense as a result of the repayment of $75.0 million of our 7.33% weighted average fixed rate notes in July 2013. These decreases were offset by an increase in interest expense related to our revolving credit facility due to an increase in weighted average borrowings based on daily balances of approximately $454.4 million during 2013 compared to approximately $283.8 million 2012, partially offset by a lower weighted average effective interest rate of approximately 2.3% during 2013 compared to approximately 3.0% during 2012.

Income Tax Expense. Income tax expense increased $99.7 million due to an increase in pretax income offset by a lower effective tax rate. The effective tax rates for 2013 and 2012 were 42.4% and 44.6%, respectively. The effective tax rate was lower due to a decrease in the impact of our state rates used to determine our deferred state tax liabilities and assets reflected in our Consolidated Balance Sheet.

## 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 only provide only partial price protection by limiting the benefit to us of increases in prices, while protecting us in the event of price

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declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits 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 and swap agreements, to protect against exposure to price declines related to our on 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, 2014, we had the following outstanding commodity derivatives:

| | | | | Collars | | | | Swaps | Asset |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Floor | | Ceiling | | | (Liability) |
| Type of Contract | Volume | | Contract Period | Range | Weighted-Average | Range | Weighted-Average | Weighted-Average | (In thousands) |
| Natural gas | 70.9 | Bcf | Jan. 2015 - Dec. 2015 | $3.86 - $3.91 | $ 3.87 | $4.27 - $4.43 | $ 4.35 | | $ 56,799 |
| Natural gas | 70.9 | Bcf | Jan. 2015 - Dec. 2015 | | | | | $ 3.92 | 64,671 |
| Natural gas | 5.2 | Bcf | Jan. 2015 - Mar. 2015 | | | | | $ 4.62 | 8,051 |
| Natural gas | 10.4 | Bcf | Apr. 2015 - Oct. 2015 | | | | | $ 3.86 | 8,291 |
| | | | | | | | | | $ 137,812 |

In the above table, natural gas prices are stated per Mcf.
The amounts set forth in the table above represent our total unrealized derivative position at December 31, 2014 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.
During 2014, natural gas collars with floor prices ranging from $3.60 to $4.37 per Mcf and ceiling prices ranging from $4.22 to $4.80 per Mcf covered 336.8 Bcf, or 66%, of natural gas production at an average price of $4.37 per Mcf. Natural gas swaps covered 102.2 Bcf, or 20%, of natural gas production at an average price of $4.06 per Mcf. Crude oil swaps covered 612 Mbbl, or 17% of crude oil production at an average price of $97.00 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 Market 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 amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these instruments.

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

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risk. The credit spread (premium or discount) is determined by comparing our fixed-rate 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 of the fixed rate notes and the revolving credit facility is based on interest rates currently available to us.

We use available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of debt are as follows:

| | December 31, 2014 | | December 31, 2013 | |
|---|---|---|---|---|
| (In thousands) | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| Debt | $1,752,000 | $1,850,867 | $1,147,000 | $1,224,273 |

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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:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive income, stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries (the "Company") at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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, 2014, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these 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 under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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.

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 27, 2015

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CABOT OIL & GAS CORPORATION
CONSOLIDATED BALANCE SHEET

| (In thousands, except share amounts) | December 31, 2014 | 2013 |
|---|---|---|
| ASSETS | | |
| Current assets | | |
| Cash and cash equivalents | $20,954 | $23,400 |
| Restricted cash | — | 28,094 |
| Accounts receivable, net | 239,009 | 222,476 |
| Inventories | 14,026 | 17,468 |
| Deferred income taxes | — | 81,855 |
| Derivative instruments | 137,603 | 3,019 |
| Other current assets | 1,855 | 2,587 |
| Total current assets | 413,447 | 378,899 |
| Properties and equipment, net (Successful efforts method) | 4,925,711 | 4,546,227 |
| Equity method investments | 68,029 | 26,892 |
| Other assets | 30,529 | 29,062 |
| | $5,437,716 | $4,981,080 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current liabilities | | |
| Accounts payable | $400,076 | $288,801 |
| Accrued liabilities | 63,669 | 73,601 |
| Income taxes payable | — | 31,591 |
| Deferred income taxes | 35,273 | — |
| Derivative instruments | — | 13,912 |
| Total current liabilities | 499,018 | 407,905 |
| Postretirement benefits | 35,827 | 33,554 |
| Long-term debt | 1,752,000 | 1,147,000 |
| Deferred income taxes | 843,876 | 1,067,912 |
| Asset retirement obligations | 124,655 | 73,853 |
| Other liabilities | 39,607 | 46,254 |
| Total liabilities | 3,294,983 | 2,776,478 |
| | | |
| Commitments and contingencies | | |
| | | |
| Stockholders' equity | | |
| Common stock: | | |
| Authorized--960,000,000 and 480,000,000 shares of $0.10 par value in 2014 and 2013, respectively | | |
| Issued--422,915,258 and 422,014,681 shares in 2014 and 2013, respectively | 42,292 | 42,201 |
| Additional paid-in capital | 710,432 | 710,940 |
| Retained earnings | 1,698,995 | 1,627,805 |
| Accumulated other comprehensive income (loss) | (2,151) | (8,361) |
| Less treasury stock, at cost: | | |
| 9,892,680 and 5,618,166 shares in 2014 and 2013, respectively | (306,835) | (167,983) |
| Total stockholders' equity | 2,142,733 | 2,204,602 |
| | $5,437,716 | $4,981,080 |

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) | 2014 | 2013 | 2012 |
| OPERATING REVENUES | | | |
| Natural gas | $1,590,625 | $1,405,262 | $934,134 |
| Crude oil and condensate | 313,889 | 291,418 | 227,933 |
| Gain (loss) on derivative instruments | 219,319 | — | (494) |
| Brokered natural gas | 34,416 | 36,450 | 34,005 |
| Other | 14,762 | 13,148 | 8,968 |
| | 2,173,011 | 1,746,278 | 1,204,546 |
| OPERATING EXPENSES | | | |
| Direct operations | 145,529 | 140,856 | 118,243 |
| Transportation and gathering | 349,321 | 229,489 | 143,309 |
| Brokered natural gas cost | 30,030 | 29,936 | 28,502 |
| Taxes other than income | 47,012 | 43,045 | 48,874 |
| Exploration | 28,746 | 18,165 | 37,476 |
| Depreciation, depletion and amortization | 632,760 | 651,052 | 451,405 |
| Impairment of oil and gas properties | 771,037 | — | — |
| General and administrative | 82,590 | 104,606 | 121,239 |
| | 2,087,025 | 1,217,149 | 949,048 |
| Earnings (loss) on equity method investments | 3,080 | 1,102 | 53 |
| Gain (loss) on sale of assets | 17,120 | 21,351 | 50,635 |
| INCOME FROM OPERATIONS | 106,186 | 551,582 | 306,186 |
| Interest expense | 73,785 | 66,044 | 68,346 |
| Income before income taxes | 32,401 | 485,538 | 237,840 |
| Income tax (benefit) expense | (72,067) | 205,765 | 106,110 |
| NET INCOME | $104,468 | $279,773 | $131,730 |
| | | | |
| Earnings per share | | | |
| Basic | $0.25 | $0.67 | $0.31 |
| Diluted | $0.25 | $0.66 | $0.31 |
| | | | |
| Weighted-average common shares outstanding | | | |
| Basic | 415,840 | 420,188 | 419,075 |
| Diluted | 417,601 | 422,375 | 421,987 |
| | | | |
| Dividends per common share | $0.08 | $0.06 | $0.04 |

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) | 2014 | 2013 | 2012 |
| Net income | $104,468 | $279,773 | $131,730 |
| Other comprehensive income (loss), net of taxes: | | | |
| Reclassification adjustment for settled cash flow hedge contracts(1) | 86,726 | (34,548) | (144,456) |
| Changes in fair value of cash flow hedge contracts(2) | (80,175) | (2,720) | 53,815 |
| Pension and postretirement benefits: | | | |
| Net gain (loss)(3) | (325) | 4,641 | 1,258 |
| Amortization of prior service cost(4) | — | — | 134 |
| Amortization of net (gain) loss(5) | (16) | 386 | 8,582 |
| Total other comprehensive income (loss) | 6,210 | (32,241) | (80,667) |
| Comprehensive income (loss) | $110,678 | $247,532 | $51,063 |

(1) Net of income taxes of $(57,477), $22,454 and $91,870 for the year ended December 31, 2014, 2013 and 2012, respectively.
(2) Net of income taxes of $53,135, $1,803 and $(34,890) for the year ended December 31, 2014, 2013 and 2012, respectively.
(3) Net of income taxes of $48, $(2,977) and $(815) for the year ended December 31, 2014, 2013 and 2012, respectively.
(4) Net of income taxes of $(87) for the year ended December 31, 2012.
(5) Net of income taxes of $10, $(255) and $(5,324) for the year ended December 31, 2014, 2013 and 2012, respectively.

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

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS

| (In thousands) | Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | $104,468 | $279,773 | $131,730 |
| Adjustments to reconcile net income to cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 632,760 | 651,052 | 451,405 |
| Impairment of oil and gas properties | 771,037 | — | — |
| Deferred income tax (benefit) expense | (112,567) | 138,380 | 80,929 |
| (Gain) loss on sale of assets | (17,120) | (21,351) | (50,635) |
| Exploration expense | 7,907 | 808 | 14,000 |
| Unrealized (gain) loss on derivative instruments | (137,603) | — | 494 |
| Amortization of debt issuance costs | 4,754 | 3,693 | 5,265 |
| Stock-based compensation, pension and other | 18,349 | 45,863 | 46,872 |
| Changes in assets and liabilities: | | | |
| Accounts receivable, net | (11,689) | (49,398) | (58,037) |
| Income taxes | (34,282) | 29,002 | 3,055 |
| Inventories | 3,441 | (3,033) | 7,104 |
| Other current assets | 733 | (428) | (1,198) |
| Accounts payable and accrued liabilities | 2,883 | (22,908) | 18,843 |
| Other assets and liabilities | 1,989 | (8,014) | 2,266 |
| Stock-based compensation tax benefit | 1,375 | (18,913) | — |
| Net cash provided by operating activities | 1,236,435 | 1,024,526 | 652,093 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Capital expenditures | (1,479,632) | (1,194,739) | (927,977) |
| Acquisitions | (214,737) | — | — |
| Proceeds from sale of assets | 39,491 | 323,501 | 169,326 |
| Restricted cash | 28,094 | (28,094) | — |
| Investment in equity method investments | (38,056) | (18,875) | (6,863) |
| Net cash used in investing activities | (1,664,840) | (918,207) | (765,514) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Borrowings from debt | 2,032,000 | 955,000 | 400,000 |
| Repayments of debt | (1,427,000) | (895,000) | (263,000) |
| Treasury stock repurchases | (138,852) | (164,634) | — |
| Dividends paid | (33,278) | (25,232) | (16,757) |
| Stock-based compensation tax benefit | (1,375) | 18,913 | — |
| Capitalized debt issuance costs | (5,626) | (2,750) | (5,005) |
| Other | 90 | 48 | (992) |
| Net cash provided by (used in) financing activities | 425,959 | (113,655) | 114,246 |
| Net (decrease) increase in cash and cash equivalents | (2,446) | (7,336) | 825 |
| Cash and cash equivalents, beginning of period | 23,400 | 30,736 | 29,911 |
| Cash and cash equivalents, end of period | $20,954 | $23,400 | $30,736 |

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, 2011 | 418,039 | $41,804 | 808 | $(3,349) | $703,475 | $104,547 | $1,258,291 | $2,104,768 |
| Net income | — | — | — | — | — | — | 131,730 | 131,730 |
| Exercise of stock appreciation rights | 438 | 44 | — | — | (6,752) | — | — | (6,708) |
| Stock amortization and vesting | 2,384 | 238 | — | — | (1,157) | — | — | (919) |
| Cash dividends at $0.04 per share | — | — | — | — | — | — | (16,757) | (16,757) |
| Other comprehensive income (loss) | — | — | — | — | — | (80,667) | — | (80,667) |
| Balance at December 31, 2012 | 420,861 | $42,086 | 808 | $(3,349) | $695,566 | $23,880 | $1,373,264 | $2,131,447 |
| Net income | — | — | — | — | — | — | 279,773 | 279,773 |
| Exercise of stock appreciation rights | 382 | 38 | — | — | (13,264) | — | — | (13,226) |
| Stock amortization and vesting | 772 | 77 | — | — | 9,725 | — | — | 9,802 |
| Tax benefit of stock-based compensation | — | — | — | — | 18,913 | — | — | 18,913 |
| Purchase of treasury stock | — | — | 4,810 | (164,634) | — | — | — | (164,634) |
| Cash dividends at $0.06 per share | — | — | — | — | — | — | (25,232) | (25,232) |
| Other comprehensive income (loss) | — | — | — | — | — | (32,241) | — | (32,241) |
| Balance at December 31, 2013 | 422,015 | $42,201 | 5,618 | $(167,983) | $710,940 | $(8,361) | $1,627,805 | $2,204,602 |
| Net income | — | — | — | — | — | — | 104,468 | 104,468 |
| Stock amortization and vesting | 900 | 91 | — | — | 867 | — | — | 958 |
| Tax benefit of stock-based compensation | — | — | — | — | (1,375) | — | — | (1,375) |
| Purchase of treasury stock | — | — | 4,275 | (138,852) | — | — | — | (138,852) |
| Cash dividends at $0.08 per share | — | — | — | — | — | — | (33,278) | (33,278) |
| Other comprehensive income (loss) | — | — | — | — | — | 6,210 | — | 6,210 |
| | 422,915 | $42,292 | 9,893 | $(306,835) | $710,432 | $(2,151) | $1,698,995 | $2,142,733 |

Balance at December
31, 2014
The accompanying notes are an integral part of these consolidated financial statements.

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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, to a lesser extent, NGLs exclusively within the continental United States. The Company also transports, stores, gathers and purchases natural gas for resale. 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 current year presentation. These reclassifications have no impact on previously reported net income.
Significant Acccounting 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 one financial institution at December 31, 2014 and in two financial institutions at December 31, 2013. 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 natural gas in storage, tubular goods and well equipment and pipeline imbalances. Natural gas in storage and tubular goods and well equipment balances are carried at the lower of average cost or market.
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 also 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.

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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.

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 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. Generally pipeline and transmission systems are depreciated over 12 to 25 years, gathering and compression equipment is depreciated over 10 years and storage equipment and facilities are depreciated over 10 to 16 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 retired, sold or abandoned properties that make up a part of an amortization base (partial field) are charged to accumulated depreciation, depletion and amortization if the units-of-production rate is not significantly affected. A gain or loss, if any, is recognized only 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 2014, 2013 and 2012, amortization associated with the Company's unproved properties was $17.4 million, $53.6 million and $18.1 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. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities are also recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2014, 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.

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Derivative and Hedging Activities

The Company enters into derivative contracts, primarily options and swaps, to manage its exposure to price fluctuations on natural gas and oil production. All derivatives 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. If the derivative does not qualify or is not designated as a cash flow hedge, changes in the fair value of the derivative are recognized currently in income. If the derivative qualifies and is designated as a cash flow hedge, changes in the fair value of the derivative are deferred in accumulated other comprehensive income to the extent the hedge is effective.

The hedging relationship between the hedging instruments and hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively if and when a hedging instrument becomes ineffective. Gains and losses deferred in accumulated other comprehensive income related to cash flow hedges that become ineffective remain unchanged until the related production occurs. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the related hedging instrument are recognized in income immediately.

Gains and losses on cash flow hedges are included in natural gas and crude oil and condensate revenues. Gains and losses on derivatives which represent hedge ineffectiveness and gains and losses on derivatives not designated or does not qualify for hedge accounting are included in operating revenues in gain (loss) on derivative instruments. The resulting cash flows are reported as cash flows from operating activities.

Through March 31, 2014, the Company elected to designate its commodity derivatives as cash flow hedges for accounting purposes. Effective April 1, 2014, the Company elected to discontinue hedge accounting for its commodity derivatives on a prospective basis.

Fair Value of Assets and Liabilities

The Company follows the authoritative accounting guidance for measuring fair value of assets and liabilities in 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. 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.

Brokered Natural Gas. Revenues and expenses related to brokering natural gas 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.

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 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, 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.

The tax benefit for stock-based compensation is included as both a cash inflow from financing activities and a cash outflow from operating activities in the Consolidated Statement of Cash Flows. The Company recognizes a tax benefit only to the extent it reduces the Company's income taxes payable.

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, 2014, 2013 and 2012, two customers accounted for approximately 14% and 10%, four customers accounted for approximately 21%, 16%, 14% and 11% and three customers accounted for approximately 18%, 12% and 10% , 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.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The guidance applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date. The guidance is effective for interim and annual periods beginning on or after December 15, 2014. The Company does not expect the adoption of this guidance to have a material impact on its financial position, results of operations or cash flows.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, as a new Topic, Accounting Standards Codification 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. This ASU is effective beginning in fiscal year 2017 and can be adopted either retrospectively or as a cumulative-effect adjustment as of the date of adoption. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, results of operations or cash flows.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern, as a new Sub-topic, Accounting Standards Codification Sub-topic 205.40. The new going concern standard codifies in generally accepted accounting principles (GAAP) management’s responsibility to evaluate whether there is substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosures. This ASU is effective for interim and annual periods beginning on or after December 15, 2016 and early adoption is permitted. The Company does not expect the adoption of this guidance to have a material impact on its financial position or results of operations.

2. Acquisitions and Divestitures

Acquisitions

In December 2014, the Company completed the acquisition of certain proved and unproved oil and gas properties in the Eagle Ford Shale in south Texas for approximately $30.5 million, subject to post-closing adjustments. Total net cash consideration paid by the Company as of the closing date was approximately $29.6 million, which reflects the impact of customary purchase price adjustments and acquisition costs.

In October 2014, the Company completed the acquisition of certain proved and unproved oil and gas properties in the Eagle Ford Shale in south Texas. Total net cash consideration paid by the Company was approximately $185.2 million, which reflects the purchase price of $210.0 million, adjusted by approximately $17.4 million for consents that the seller was unable to obtain for certain leaseholds prior to closing and approximately $8.0 million for the impact of customary purchase price adjustments and acquisition costs. In addition, the Company also assumed a liability of approximately $1.2 million related to asset retirement obligations of the wells acquired.

The Company accounted for these transactions as an asset purchase, whereby the identifiable assets acquired were recorded at cost, with the respective assigned carrying amount based on the relative fair value of the unproved and proved properties at the acquisition date. The fair value measurement of assets acquired was based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and gas properties were measured using discounted future cash flows. The discount factor used was 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. Significant inputs to the valuation of oil and gas properties include (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) 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%.

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Divestitures

The Company recognized an aggregate net gain on sale of assets of $17.1 million, $21.4 million and $50.6 million for the years ended December 31, 2014, 2013 and 2012, respectively.

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

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

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

In December 2012, the Company sold certain proved oil and gas properties located in south Texas to a private company for $29.9 million, and recognized an $18.2 million loss on sale of assets.

In June 2012, the Company sold a 35% non-operated working interest associated with certain of its Pearsall Shale undeveloped leaseholds in south Texas to a wholly owned subsidiary of Osaka Gas Co., Ltd. (Osaka) for total consideration of approximately $250.0 million. The Company received $125.0 million in cash proceeds and Osaka agreed to fund 85% of the Company's share of future drilling and completion costs associated with these leaseholds until it has paid approximately $125.0 million in accordance with a joint development agreement entered into at closing. The Company recognized a $67.0 million gain on sale of assets associated with this sale. The drilling and completion carry was fully satisfied in 2013.

In 2012, the Company sold various other unproved oil and gas properties and other assets for approximately $14.4 million and recognized an aggregate net gain of $1.8 million.

3. Properties and Equipment

Properties and equipment are comprised of the following:

| | December 31, | |
|---|---|---|
| (In thousands) | 2014 | 2013 |
| Proved oil and gas properties | $7,984,979 | $6,362,570 |
| Unproved oil and gas properties | 492,208 | 375,428 |
| Gathering and pipeline systems | 241,272 | 239,958 |
| Land, building and other equipment | 109,758 | 94,243 |
| | 8,828,217 | 7,072,199 |
| Accumulated depreciation, depletion and amortization | (3,902,506) | (2,525,972) |
| | $4,925,711 | $4,546,227 |

Impairment

In December 2014, the Company recorded a $771.0 million impairment of oil and gas properties in certain non-core fields, primarily in east Texas. The impairment of these fields was due to a significant decline in commodity prices in late 2014 and management's decision not to pursue any further activity in these non-core areas in the current price environment. These fields were reduced to fair value of approximately $86.5 million using discounted future cash flows.

The fair value of the impaired fields 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) 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%.

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Capitalized Exploratory Well Costs

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Balance at beginning of period | $— | $10,390 | $5,328 |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | 10,557 | — | 10,390 |
| Reclassifications to wells, facilities, and equipment based on the determination of proved reserves | — | (10,198) | — |
| Capitalized exploratory well costs charged to expense | — | (192) | (5,328) |
| Balance at end of period | $10,557 | $— | $10,390 |

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

| | December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Capitalized exploratory well costs that have been capitalized for a period of one year or less | $10,557 | $— | $10,390 |
| Capitalized exploratory well costs that have been capitalized for a period greater than one year | — | — | — |
| | $10,557 | $— | $10,390 |

4. Equity Method Investments

Constitution Pipeline Company, LLC

In April 2012, the Company acquired a 25% equity interest in Constitution Pipeline Company, LLC (Constitution), which thereby became an unconsolidated investee. Constitution 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. The expected in-service date for the new pipeline is 2016. Accordingly, the Company expects to contribute approximately $139.7 million over the next two years.

During 2014, 2013 and 2012, the Company made contributions of $34.2 million, $18.9 million and $6.9 million, respectively, to fund costs associated with the project. The Company's net book value in this equity investment was $64.3 million and $26.9 million as of December 31, 2014 and 2013, respectively, and is included in equity method investments in the Consolidated Balance Sheet. There were no material earnings or losses associated with Constitution during 2014, 2013 or 2012.

Meade Pipeline Co LLC

In February 2014, the Company acquired a 20% equity interest in Meade Pipeline Co LLC (Meade). Meade 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 $135.3 million over the next three years. The expected in-service date for the new pipeline is scheduled for the second half of 2017.

During 2014, the Company made contributions of approximately $3.9 million to Meade. The Company’s net book value in this equity investment was $3.8 million as of December 31, 2014 and is included in equity method investments in the Consolidated Balance Sheet. There were no material earnings or losses associated with Meade during 2014.

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5. Debt and Credit Agreements

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

| (In thousands) | December 31, 2014 | 2013 |
|---|---|---|
| Long-Term Debt | | |
| 7.33% weighted-average fixed rate notes | $20,000 | $20,000 |
| 6.51% weighted-average fixed rate notes | 425,000 | 425,000 |
| 9.78% fixed rate notes | 67,000 | 67,000 |
| 5.58% weighted-average fixed rate notes | 175,000 | 175,000 |
| 3.65% weighted-average fixed rate notes | 925,000 | — |
| Revolving credit facility | 140,000 | 460,000 |
| | $1,752,000 | $1,147,000 |

The Company has debt maturities of $20.0 million due in 2016 and $312.0 million due in 2018. In addition, the revolving credit facility matures in 2017. No other tranches of debt are due within the next five years.

At December 31, 2014, the Company was in compliance with all restrictive financial covenants in both the revolving credit facility and fixed rate notes.

Fixed Rate Notes

The Company has various issuances of fixed rate notes. Under the terms of the various fixed rate note purchase 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. There are also various other restrictive covenants customarily found in such debt instruments. Those covenants include a minimum asset coverage ratio (present value of proved reserves plus adjusted cash to indebtedness and other liabilities) of 1.75 to 1.0 and a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of 2.8 to 1.0. The notes are also subject to customary events of default. With the exception of the 7.33% weighted-average fixed rate notes, the Company is required to offer to prepay all other fixed rate notes upon specified change in control events accompanied by a ratings decline below investment grade.

Interest on each of the fixed rate notes is payable semi-annually.

7.33% Weighted-Average Fixed Rate Notes

In July 2001, the Company issued $170 million of senior unsecured fixed rate notes to a group of seven 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 | $75,000,000 | 10 years | July 2011 | 7.26 | % |
| Tranche 2 | $75,000,000 | 12 years | July 2013 | 7.36 | % |
| Tranche 3 | $20,000,000 | 15 years | July 2016 | 7.46 | % |

As of December 31, 2014, the Company has repaid $150 million of aggregate maturities associated with the 7.33% weighted-average fixed rate notes.

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6.51% Weighted-Average Fixed Rate Notes

In July 2008, the Company issued $425 million of senior unsecured fixed rate 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 | % |

9.78% Fixed Rate Notes

In December 2008, the Company issued $67 million aggregate principal amount of 10 year 9.78% unsecured fixed rate senior notes to a group of four institutional investors in a private placement.

5.58% Weighted-Average Fixed Rate Notes

In December 2010, the Company issued $175 million of senior unsecured fixed rate 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 Fixed Rate Notes

In September 2014, the Company issued $925 million of senior unsecured fixed rate 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 | % |

In conjunction with the issuance of the 3.65% weighted average fixed rate notes in September 2014, the Company incurred approximately $5.6 million of debt issuance costs, which were capitalized and will be amortized over the term of the notes. The amortization of debt issuance costs is included in interest expense in the Consolidated Statement of Operations.

Revolving Credit Agreement

The Company's revolving credit facility matures in May 2017 and is unsecured. The available credit line is subject to adjustment from time to time on the basis of (1) the projected present value (as determined by the banks based on the Company's reserve reports and engineering reports) of estimated future net cash flows from certain proved oil and gas reserves and certain other assets of the Company (the "Borrowing Base") and (2) the outstanding principal balance of the Company's fixed rate notes. While the Company does not expect a reduction in the available credit line, in the event that it is adjusted below that level in connection with scheduled redetermination or due to a termination of hedge positions, the Company has a period of six months to reduce its outstanding debt in equal monthly installments to the adjusted credit line available. At December 31, 2014, the Company had a $1.4 billion credit line under the revolving credit facility.

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 in connection with certain acquisitions or sales of oil and gas properties. Effective April 15, 2014, the lenders under the Company’s revolving credit facility approved an increase in the Company’s Borrowing Base from $2.3 billion to $3.1 billion as part of the annual redetermination under the terms of the revolving credit facility agreement. The commitments under the revolving credit facility remain unchanged at $1.4 billion.

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Interest rates under the revolving credit facility are based on Euro-Dollars (LIBOR) or Alternate Base Rate (ABR) indications, plus a margin. The associated margins increase if the total indebtedness under the revolving credit facility and the Company's fixed rate notes as a percentage of the Borrowing Base is greater than the percentages shown below:

| | Debt Percentage | | | | |
|---|---|---|---|---|---|
| | <25% | 25% <50% | 50% <75% | 75% <90% | 90% |
| Eurodollar loans | 1.50 % | 1.75 % | 2.00 % | 2.25 % | 2.50 % |
| ABR loans | 0.50 % | 0.75 % | 1.00 % | 1.25 % | 1.50 % |

The revolving credit facility provides for a commitment fee on the unused available balance at annual rates ranging from 0.375% to 0.50%.

The revolving credit facility also contains various customary covenants, 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 an asset coverage ratio of the present value of proved reserves plus adjusted cash to indebtedness and other liabilities of 1.75 to 1.0.

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

In addition, the revolving credit facility includes a customary condition to the Company's borrowings under the facility that a material adverse change has not occurred with respect to the Company.

At December 31, 2014, the Company had $140.0 million of borrowings outstanding under its revolving credit facility and $1.3 billion available for future borrowings. The Company's weighted-average effective interest rates for the revolving credit facility during the years ended December 31, 2014, 2013 and 2012 were approximately 2.2%, 2.3% and 3.0%, respectively. As of December 31, 2014 and 2013, the weighted-average interest rate on the Company's revolving credit facility was approximately 2.4% and 2.0%, respectively.

6. Derivative Instruments and Hedging Activities

The Company periodically enters into commodity derivatives to manage its exposure to price fluctuations on 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.

Through March 31, 2014, the Company elected to designate its commodity derivatives as cash flow hedges for accounting purposes. Effective April 1, 2014, the Company elected to discontinue hedge accounting for its commodity derivatives on a prospective basis. As a result of discontinuing hedge accounting, the unrealized loss included in accumulated other comprehensive income (loss) as of April 1, 2014 of $73.4 million ($44.2 million net of tax) was frozen and reclassified into natural gas and crude oil and condensate revenues in the Statement of Operations throughout 2014 as the underlying hedged transactions occurred. As of December 31, 2014, there are no gains or losses deferred in accumulated other comprehensive income (loss) associated with the Company's commodity derivatives.

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As of December 31, 2014, the Company had the following outstanding commodity derivatives instruments:

| | | | | Collars | | | | Swaps |
|---|---|---|---|---|---|---|---|---|
| | | | | Floor | | Ceiling | | |
| Type of Contract | Volume | | Contract Period | Range | Weighted-Average | Range | Weighted-Average | Weighted-Average |
| Natural gas | 70.9 | Bcf | Jan. 2015 - Dec. 2015 | $3.86 - $3.91 | $3.87 | $4.27 - $4.43 | $4.35 | |
| Natural gas | 70.9 | Bcf | Jan. 2015 - Dec. 2015 | | | | | $3.92 |
| Natural gas | 5.2 | Bcf | Jan. 2015 - Mar. 2015 | | | | | $4.62 |
| Natural gas | 10.4 | Bcf | Apr. 2015 - Oct. 2015 | | | | | $3.86 |

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

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 | 2014 | 2013 | 2014 | 2013 |
| Derivatives Designated as Hedges | | | | | |
| Commodity contracts | Derivative instruments (current assets) | $— | $3,019 | $— | $— |
| Commodity contracts | Derivative instruments (current liabilities) | — | — | — | 13,912 |
| Derivatives Not Designated as Hedges | | | | | |
| Commodity contracts | Derivative instruments (current assets) | 137,603 | — | — | — |
| | | $137,603 | $3,019 | $— | $13,912 |

Offsetting of Derivative Assets and Liabilities in the Consolidated Balance Sheet

| | December 31, | |
|---|---|---|
| (In thousands) | 2014 | 2013 |
| Derivative Assets | | |
| Gross amounts of recognized assets | $137,603 | $13,792 |
| Gross amounts offset in the statement of financial position | — | (10,773) |
| Net amounts of assets presented in the statement of financial position | 137,603 | 3,019 |
| Gross amounts of financial instruments not offset in the statement of financial position | 2,338 | 373 |
| Net amount | $139,941 | $3,392 |
| | | |
| Derivative Liabilities | | |
| Gross amounts of recognized liabilities | $— | $24,685 |
| Gross amounts offset in the statement of financial position | — | (10,773) |
| Net amounts of liabilities presented in the statement of financial position | — | 13,912 |
| Gross amounts of financial instruments not offset in the statement of financial position | — | — |
| Net amount | $— | $13,912 |

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Effect of Derivative Instruments on Accumulated Other Comprehensive Income (Loss)

The amount of gain (loss) recognized in accumulated other comprehensive income (loss) on derivatives (effective portion) is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Commodity contracts | $(133,310) | $(4,523) | $88,705 |

The amount of gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion) is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014[1] | 2013 | 2012 |
| Natural gas revenues | $(143,577) | $52,733 | $225,108 |
| Crude oil and condensate revenues | (626) | 4,269 | 11,218 |
| | $(144,203) | $57,002 | $236,326 |

(1) The Company ceased hedge accounting effective April 1, 2014. As a result, a loss of approximately $73.4 million related to amounts previously frozen in accumulated other comprehensive income (loss) were reclassified into income during 2014.

Effect of Derivative Instruments on the Consolidated Statement of Operations

The amount of gain (loss) recognized in the Consolidated Statement of Operations on derivative instruments is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Derivatives Designated as Hedges | | | |
| Realized | | | |
| Natural gas | $(70,557) | $52,733 | $225,108 |
| Crude oil and condensate | (218) | 4,269 | 11,218 |
| | $(70,775) | $57,002 | $236,326 |
| Derivatives Not Designated as Hedges | | | |
| Realized | | | |
| Natural gas[1] | $(73,020) | $— | $— |
| Crude oil and condensate[1] | (408) | — | — |
| Gain (loss) on derivative instruments | 81,716 | — | — |
| Unrealized | | | |
| Gain (loss) on derivative instruments | 137,603 | — | (494) |
| | $145,891 | $— | $(494) |
| | $75,116 | $57,002 | $235,832 |

(1) Relates entirely to the reclassification from accumulated other comprehensive income (loss) of previously frozen losses associated with derivatives that were de-designated as cash flow hedges on April 1, 2014.

For the years ended December 31, 2014, 2013 and 2012, respectively, there was no ineffectiveness recorded in the Company’s Consolidated Statement of Operations related to its derivative instruments designated as cash flow hedges.

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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 our derivative contracts are with multiple counterparties to minimize our 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. 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.

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

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments and acquisitions of oil and gas properties, at fair value on a nonrecurring basis. During the year ended December 31, 2014, the Company acquired certain oil and gas properties that were allocated based on the relative fair value of the proved and unproved properties and also recorded an impairment charge related to certain oil and gas properties. Refer to Note 2 for additional disclosures related to the non-recurring fair value measurements associated with these acquisitions and Note 3 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, 2014, 2013 and 2012 additional disclosures were not provided.

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.

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 as of December 31, 2014 |
|---|---|---|---|---|
| Assets | | | | |
| Deferred compensation plan | $13,115 | $— | $— | $13,115 |
| Derivative contracts | — | 51,645 | 85,958 | 137,603 |
| Total assets | $13,115 | $51,645 | $85,958 | $150,718 |
| Liabilities | | | | |
| Deferred compensation plan | $28,932 | $— | $— | $28,932 |
| Derivative contracts | — | — | — | — |
| Total liabilities | $28,932 | $— | $— | $28,932 |

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| (In thousands) | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Balance as of December 31, 2013 |
|---|---|---|---|---|
| Assets | | | | |
| Deferred compensation plan | $12,507 | $— | $— | $12,507 |
| Derivative contracts | — | — | 13,792 | 13,792 |
| Total assets | $12,507 | $— | $13,792 | $26,299 |
| Liabilities | | | | |
| Deferred compensation plan | $33,211 | $— | $— | $33,211 |
| Derivative contracts | — | 6,983 | 17,702 | 24,685 |
| Total liabilities | $33,211 | $6,983 | $17,702 | $57,896 |

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. Such quotes 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 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 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) | 2014 | 2013 | 2012 |
| Balance at beginning of period | $(3,910) | $41,159 | $195,127 |
| Total gains (losses) (realized or unrealized): | | | |
| Included in earnings | 35,067 | 52,733 | 224,614 |
| Included in other comprehensive income | 3,755 | (45,069) | (157,478) |
| Settlements | 51,046 | (52,733) | (221,489) |
| Transfers in and/or out of level 3 | — | — | 385 |
| Balance at end of period | $85,958 | $(3,910) | $41,159 |
| Change in unrealized gains (losses) relating to assets and liabilities still held at the end of the period | $85,958 | $— | $— |

There were no transfers between Level 1 and Level 2 fair value measurements for the years ended December 31, 2014, 2013 and 2012.

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Fair Value of Other Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments. Based on the inputs used to fair value these financial 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 fixed rate 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 fixed rate 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 amounts and fair values of debt are as follows:

| | December 31, 2014 | | December 31, 2013 | |
|---|---|---|---|---|
| (In thousands) | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| Debt | $1,752,000 | $1,850,867 | $1,147,000 | $1,224,273 |

8. Asset Retirement Obligations

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

| (In thousands) | Year Ended December 31, 2014 |
|---|---|
| Balance at beginning of period | $75,853 |
| Liabilities incurred | 7,220 |
| Liabilities settled and divested | (1,474) |
| Liabilities acquired | 1,206 |
| Accretion expense | 5,110 |
| Change in estimate | 38,740 |
| Balance at end of period | $126,655 |

The change in estimate during 2014 is attributable to an increase in cost of materials and services. The increase is primarily due to an increase in demand, more costly and rigorous plugging and abandonment techniques associated with the Company's wells in certain areas of its operations and the lack of availability of service providers in areas with minimal activity.

As of both December 31, 2014 and 2013, approximately $2.0 million is included in accrued liabilities in the Consolidated Balance Sheet, which represents the current portion of the Company’s asset retirement obligation.

9. Commitments and Contingencies

Transportation and Gathering Agreements

The Company has entered into certain natural gas, oil and NGL transportation and gathering agreements with various pipeline carriers. Under certain of these agreements, the Company is obligated to transport minimum daily quantities, or pay for any deficiencies at a specified rate. 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. In most cases, the Company's production commitment to these pipelines is expected to exceed minimum daily quantities provided in the agreements. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability.

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As of December 31, 2014, the Company's future minimum obligations under transportation and gathering agreements are as follows:

| (In thousands) | |
|---|---|
| 2015 | $130,411 |
| 2016 | 161,675 |
| 2017 | 163,573 |
| 2018 | 138,917 |
| 2019 | 129,245 |
| Thereafter | 1,226,791 |
| | $1,950,612 |

In January 2015, the Company entered into a natural gas transportation agreement associated with the Company's production in Pennsylvania. This agreement increased the Company's future aggregate obligations under its transportation commitments by approximately $105.9 million over the next 10 years.

Drilling Rig Commitments

As of December 31, 2014, the Company entered into certain drilling rig commitments for three drilling rigs for its capital program in the Marcellus Shale and Eagle Ford Shale with initial terms ranging from two to three years. As of December 31, 2014, the future minimum commitments under these agreements are $14.4 million in 2015 and $7.0 million in 2016.

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 $10.8 million, $12.3 million and $11.6 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2014 are as follows:

| (In thousands) | |
|---|---|
| 2015 | $5,818 |
| 2016 | 3,469 |
| 2017 | 2,873 |
| 2018 | 2,312 |
| 2019 | 1,877 |
| Thereafter | 9,464 |
| | $25,813 |

Legal Matters

Enexco Litigation

In October 2010, the Company was sued in the Texas District Court in Shelby County, Texas by a group of plaintiffs led by Enexco, Inc. The parties are conducting discovery. No trial date has been set. The plaintiffs allege that the Company was negligent and grossly negligent in conducting drilling operations on a natural gas well in Shelby County, Texas in which the plaintiffs were drilling participants in 2009. The plaintiffs allege that negligence in the Company’s drilling operations damaged not only that well, but also two nearby natural gas wells in which the plaintiffs owned interests. The plaintiffs seek damages for lost reserves of all three wells, costs of operations and associated facilities and attorneys’ fees, as well as exemplary damages based upon claims of gross negligence.

The Company has denied that its drilling operations were negligent and is vigorously disputing both the merits of plaintiffs’ claims and their allegations of damages. The plaintiffs seek actual damages of $10.0 million and exemplary damages of up to two and one half times of actual damages. The Company has established a reserve to provide for this potential liability based upon management’s best estimate of the potential loss; such reserve was not material.

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Other

The Company is a defendant in various other 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 is not 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.

10. Income Taxes

Income tax expense is summarized as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Current | | | |
| Federal | $44,887 | $56,544 | $24,618 |
| State | (4,387) | 10,841 | 563 |
| | 40,500 | 67,385 | 25,181 |
| Deferred | | | |
| Federal | (32,375) | 111,147 | 57,704 |
| State | (80,192) | 27,233 | 23,225 |
| | (112,567) | 138,380 | 80,929 |
| Income tax (benefit) expense | $(72,067) | $205,765 | $106,110 |

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Statutory federal income tax rate | 35 % | 35 % | 35 % |
| Computed "expected" federal income tax | $11,341 | $169,938 | $83,244 |
| Deferred tax adjustment related to change in overall state tax rate | (86,956) | 15,220 | 13,596 |
| State income tax, net of federal income tax benefit | 903 | 17,513 | 9,609 |
| Valuation allowance | 3,977 | — | 262 |
| Uncertain tax positions | (1,974) | 2,400 | — |
| Other, net | 642 | 694 | (601) |
| Income tax expense | $(72,067) | $205,765 | $106,110 |

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The composition of deferred tax liabilities and deferred tax assets were as follows:

| (In thousands) | December 31, 2014 | 2013 |
|---|---|---|
| Deferred Tax Assets | | |
| Net operating loss carryforward | $141,961 | $78,182 |
| Alternative minimum tax carryforward | 227,719 | 182,212 |
| Foreign tax credit | 4,525 | 4,822 |
| Derivative instruments | — | 3,946 |
| Incentive compensation | 21,961 | 36,450 |
| Deferred compensation | 9,531 | 11,988 |
| Post-retirement benefits | 13,689 | 13,965 |
| Other | 747 | 3,619 |
| Total | 420,133 | 335,184 |
| Deferred Tax Liabilities | | |
| Properties and equipment | 1,248,532 | 1,321,241 |
| Derivative instruments | 50,750 | — |
| Total | 1,299,282 | 1,321,241 |
| Net deferred tax liabilities | $879,149 | $986,057 |

As of December 31, 2014, the Company had alternative minimum tax credit carryforwards of $227.7 million, which do not expire and can be used to offset regular income taxes in future years to the extent that regular income taxes exceed the alternative minimum tax in any such year. The Company also had net operating loss carryforwards of $399.8 million and $483.7 million for federal and state reporting purposes, respectively, the majority of which will expire between 2020 and 2034. The Company believes it is more likely than not that these deferred tax benefits will be utilized prior to their expiration. Tax benefits related to employee stock-based compensation included in net operating loss carryforwards but not reflected in deferred tax assets as of December 31, 2014 are approximately $108.6 million.

For state income tax purposes, the Company must estimate the respective amounts of future earnings that are subject to income tax in the various states in which the Company operates.  These estimates may change based on a variety of factors, including but not limited to the composition and location of the Company’s asset base and the location of the Company’s customers.  In 2014, the Company’s effective tax rate decreased compared to 2013 due to a change in estimated deferred state tax liabilities reflected in the Company’s Consolidated Balance Sheet, which was based on updated state apportionment factors in states in which it operates.

Unrecognized Tax Benefits

A reconciliation of unrecognized tax benefits is as follows:

| (In thousands) | Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Balance at beginning of year | $3,700 | $— | $— |
| Additions based on tax provisions related to the current year | — | 3,700 | — |
| Additions for tax positions of prior years | — | — | — |
| Reductions for tax positions of prior years | (3,037) | — | — |
| Settlements | — | — | — |
| Balance at end of year | $663 | $3,700 | $— |

During 2013, the Company recorded unrecognized tax benefits of $3.7 million based on the allocation of certain gains associated with its divestitures for purposes of computing state income taxes. These benefits were reduced during 2014 by $3.0 million based on changes to the Company's state tax rates. If recognized, the net tax benefit of $0.7 million would not have a material effect on the Company's effective tax rate.

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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 2010 or by federal authorities before 2011. The Company is not currently under examination by the Internal Revenue Service.

11. Employee Benefit Plans

Pension Plan

In September 2010, the Company terminated its non-contributory, defined benefit pension plan for all full-time employees, referred to as the tax qualified defined benefit pension plan (qualified pension plan) and its unfunded non-qualified supplemental pension plan to ensure payments to certain executive officers of amounts to which they would have been entitled under the provisions of the pension plan, but for limitations imposed by federal tax laws, referred to as the supplemental non-qualified pension arrangements (non-qualified pension plan). The non-qualified pension plan was liquidated in 2012. On March 14, 2012, the Internal Revenue Service provided the Company with a favorable determination letter for the termination of the Company's qualified pension plan, which was liquidated in 2013.

The Company recorded net periodic pension cost, which is included in general and administrative expense in the Consolidated Statement of Operations, of $19.5 million for the year ended December 31, 2012. There was no net periodic pension cost recorded in 2014 and 2013.

Postretirement Benefits Other than Pensions

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. The Company was providing postretirement benefits to 278 retirees and their dependents at the end of 2014 and 270 retirees and their dependents at the end of 2013.

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 funded 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) | 2014 | 2013 | 2012 |
| Change in Benefit Obligation | | | |
| Benefit obligation at beginning of year | $34,995 | $40,168 | $39,969 |
| Service cost | 1,295 | 1,739 | 1,513 |
| Interest cost | 1,343 | 1,500 | 1,537 |
| Actuarial (gain) loss | 373 | (7,618) | (2,073) |
| Benefits paid | (930) | (794) | (778) |
| Benefit obligation at end of year | $37,076 | $34,995 | $40,168 |
| Change in Plan Assets | | | |
| Fair value of plan assets at end of year | — | — | — |
| Funded status at end of year | $(37,076) | $(34,995) | $(40,168) |

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Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet consist of the following:

| | December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Current liabilities | $1,249 | $1,441 | $1,304 |
| Long-term liabilities | 35,827 | 33,554 | 38,864 |
| | $37,076 | $34,995 | $40,168 |

Amounts Recognized in Accumulated Other Comprehensive Income (Loss)

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

| | December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Net actuarial loss | $3,408 | $3,010 | $11,269 |
| | $3,408 | $3,010 | $11,269 |

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Components of Net Periodic Postretirement Benefit Cost | | | |
| Service cost | $1,295 | $1,739 | $1,513 |
| Interest cost | 1,343 | 1,500 | 1,537 |
| Amortization of net (gain) loss | (26) | 641 | 824 |
| Net periodic postretirement cost | $2,612 | $3,880 | $3,874 |
| Other Changes in Benefit Obligations Recognized in Other Comprehensive Income (Loss) | | | |
| Net (gain) loss | $373 | $(7,618) | $(2,073) |
| Amortization of net (gain) loss | 26 | (641) | (824) |
| Total recognized in other comprehensive income (loss) | 399 | (8,259) | (2,897) |
| Total recognized in net periodic benefit cost and other comprehensive income (loss) | $3,011 | $(4,379) | $977 |

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Assumptions

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

| | December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| Discount rate[1] | 4.00 | % | 4.75 | % | 4.00 | % |
| Health care cost trend rate for medical benefits assumed for next year | 6.00 | % | 6.50 | % | 7.00 | % |
| Rate to which the cost trend rate is assumed to decline (the ultimate trend rate) | 4.50 | % | 4.50 | % | 5.00 | % |
| Year that the rate reaches the ultimate trend rate | 2018 | | 2018 | | 2015 | |

(1) Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2014, 2013 and 2012, respectively, the beginning of year discount rates of 4.75%, 4.00% and 4.25% 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.

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 | $ 678 | $(308 | ) |
| Effect on postretirement benefit obligation | 6,098 | (4,893 | ) |

Cash Flows

Contributions. The Company expects to contribute approximately $1.3 million to the postretirement benefit plan in 2015.

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) | |
|---|---|
| 2015 | 1,274 |
| 2016 | 1,333 |
| 2017 | 1,477 |
| 2018 | 1,623 |
| 2019 | 1,820 |
| Years 2020 - 2024 | 11,329 |

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. During the years ended December 31, 2014, 2013 and 2012, the Company made contributions of $7.2 million, $6.9 million and $6.3 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 $13.1 million and $12.5 million at December 31, 2014 and 2013, respectively, and is included in other assets in the Consolidated Balance Sheet. Related liabilities, including the Company's common stock, totaled $28.9 million and $33.2 million at December 31, 2014 and 2013, respectively, and are included in other liabilities in the 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, 2014, 534,174 shares of the Company's common stock were held in the rabbi trust. These shares were recorded at the market value on the date of deferral, which totaled $5.7 million at December 31, 2014 and 2013, respectively, and is included in additional paid-in capital in stockholders' equity in the Consolidated Balance Sheet. During 2014, the Company recognized $4.9 million in general and administrative expense in the Consolidated Statement of Operations representing the 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 $0.8 million, $0.7 million and $0.7 million in 2014, 2013 and 2012, respectively, which are included in general and administrative expense in the Consolidated Statement of Operations.

12. Capital Stock

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 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 million shares of common stock may be issued under the 2014 Incentive Plan. Under the 2014 Incentive Plan, no more than 10 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, 2014, approximately 18.0 million shares are available for issuance under the 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.

Increase in Authorized Shares

In May 2014, the Company's shareholders approved an increase in the authorized number of shares of common stock from 480 million to 960 million shares.

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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, 2014 and 2013, the Company repurchased 4.3 million shares for a total cost of $138.9 million and 4.8 million shares for a total cost of $164.6 million, respectively. There were no share repurchases in 2012. Since the authorization date, the Company has repurchased 29.9 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 $388.4 million. No treasury shares have been delivered or sold by the Company subsequent to the repurchase. As of December 31, 2014, 9.9 million shares were held as treasury stock.

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 fixed rate note or credit agreements in place have restricted payment provisions or other provisions limiting dividends.

13. Stock-Based Compensation

General

Compensation expense for stock-based awards for the years ended December 31, 2014, 2013 and 2012 was $21.5 million, $51.8 million and $33.5 million, respectively, and is included in general and administrative expense in the Consolidated Statement of Operations.

For the years ended December 31, 2014 and 2013, the Company realized $(1.4) million and $18.9 million tax (expense) benefit related to the federal tax deduction in excess of book compensation cost for employee stock-based compensation. The Company is able to recognize tax benefits only to the extent they reduce the Company's income taxes payable. There were no excess tax benefits recorded for the year ended December 31, 2012 as the Company was in a net operating loss position for federal income tax purposes.

Restricted Stock Awards

Restricted stock awards are granted from time to time to employees of the Company. The fair value of restricted stock grants under the 2004 Incentive Plan is based on the average of the high and low stock price on the grant date and the fair value of restricted stock grants under the the 2014 Incentive Plan (approved by shareholders on May 1, 2014) 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 3 or 4 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 all 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. 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 ranging from 5.0% to 7.0% 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, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| | 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 | 27,806 | $20.53 | 71,508 | $11.82 | 476,388 | $9.18 |
| Granted | 47,500 | 34.76 | 7,200 | 35.70 | 13,100 | 18.42 |
| Vested | (17,437) | 15.84 | (50,902) | 10.44 | (402,800) | 9.03 |
| Forfeited | (8,000) | 35.00 | — | — | (15,180) | 8.80 |
| Outstanding at end of period[(1)(2)] | 49,869 | $33.40 | 27,806 | $20.53 | 71,508 | $11.82 |

(1) As of December 31, 2014, the aggregate intrinsic value was $1.5 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2014 by the number of non-vested restricted stock awards outstanding.

(2) As of December 31, 2014, the weighted average remaining contractual term of non-vested restricted stock awards outstanding was 1.9 years.

Compensation expense recorded for all restricted stock awards for the years ended December 31, 2014, 2013 and 2012 was $1.0 million, $0.2 million and $1.1 million, respectively. Unamortized expense as of December 31, 2014 for all outstanding restricted stock awards was $0.8 million and will be recognized over the next year.

The total fair value of restricted stock awards that vested during 2014, 2013 and 2012 was $0.6 million, $1.6 million and $3.6 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 granted under the 2004 Incentive Plan is based on the average of the high and low stock price on the grant date and the fair value of restricted stock units granted under the the 2014 Incentive Plan (approved by shareholders on May 1, 2014) 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, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| | 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 | 566,321 | $10.75 | 515,468 | $9.10 | 687,308 | $7.88 |
| Granted and fully vested | 37,893 | 38.28 | 50,853 | 27.53 | 76,608 | 18.28 |
| Issued | — | — | — | — | (248,448) | 8.56 |
| Forfeited | — | — | — | — | — | — |
| Outstanding at end of period[(1)(2)] | 604,214 | $12.48 | 566,321 | $10.75 | 515,468 | $9.10 |

(1) As of December 31, 2014, the aggregate intrinsic value was $17.9 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2014 by the number of outstanding restricted stock units.

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(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.

Compensation expense recorded for all restricted stock units for the years ended December 31, 2014, 2013 and 2012 was $1.5 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 following table is a summary of SAR activity:

| | Year Ended December 31, 2014 | | 2013 | | 2012 | |
|---|---|---|---|---|---|---|
| | Shares | Weighted-Average Exercise Price | Shares | Weighted-Average Exercise Price | Shares | Weighted-Average Exercise Price |
| Outstanding at beginning of period | 667,764 | $12.63 | 1,722,444 | $9.75 | 2,576,260 | $8.02 |
| Granted | — | — | — | — | 240,884 | 17.59 |
| Exercised | — | — | (1,054,680 ) | 7.92 | (1,094,700 ) | 7.42 |
| Forfeited or expired | — | — | — | — | — | — |
| Outstanding at end of period[1] | 667,764 | $12.63 | 667,764 | $12.63 | 1,722,444 | $9.75 |
| Exercisable at end of period[2] | 590,960 | $11.98 | 386,582 | $11.33 | 1,145,972 | $7.97 |

(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, 2014, the aggregate intrinsic value and weighted-average remaining contractual term of SARs outstanding was $11.3 million and 3.3 years, respectively.

(2) As of December 31, 2014, the aggregate intrinsic value and weighted-average remaining contractual term of SARs exercisable was $10.4 million and 3.2 years, respectively.

Compensation expense recorded for all outstanding SARs for the years ended December 31, 2014, 2013 and 2012 was $0.1 million, $0.3 million and $1.9 million, respectively. In 2012 there was $1.2 million related to the immediate expensing of shares granted to retirement-eligible employees. As of December 31, 2014, there was no remaining unamortized expense to be recognized for the outstanding SARs.

The Company calculates the fair value of SARs using the Black-Scholes model. The assumptions used in the Black-Scholes calculation on the date of grant for SARs are as follows:

| | Year Ended December 31, 2012 | |
|---|---|---|
| Weighted-average value per SAR granted during the period | $8.16 | |
| Assumptions | | |
| Stock price volatility | 55.3 | % |
| Risk free rate of return | 0.9 | % |
| Expected dividend yield | 0.3 | % |
| Expected term (in years) | 5.0 | |

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

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continuously compounded equivalent of the U.S. Treasury (Nominal 10) 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 6% 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 award grants based on internal performance metrics is based on the average of the high and low stock price on the grant date and 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 Company's probability assessment at December 31, 2014, 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, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| | 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 | 1,657,980 | $16.25 | 1,919,640 | $12.27 | 2,627,900 | $8.12 |
| Granted | 241,130 | 39.43 | 379,540 | 26.62 | 567,360 | 17.59 |
| Issued and fully vested | (751,780) | 10.19 | (610,960) | 10.13 | (1,189,920) | 5.66 |
| Forfeited | (58,370) | 23.57 | (30,240) | 17.06 | (85,700) | 12.11 |
| Outstanding at end of period | 1,088,960 | $25.18 | 1,657,980 | $16.25 | 1,919,640 | $12.27 |

Hybrid Performance Share Awards. The Hybrid Performance Share Awards have a three-year graded performance period. The 2014 and the 2013 awards vest 25% on each of the first and second anniversary dates and 50% on the third anniversary and the 2012 awards vest one-third on each anniversary date, 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, 2014, it is considered probable that the criteria for these awards will be met.

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

| | Year Ended December 31, 2014 | | 2013 | | 2012 | |
|---|---|---|---|---|---|---|
| | 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 | 450,212 | $18.96 | 592,162 | $13.11 | 759,328 | $9.16 |
| Granted | 123,257 | 39.43 | 169,980 | 26.62 | 234,922 | 17.59 |
| Issued and fully vested | (244,408) | 15.41 | (311,930) | 12.03 | (402,088) | 8.27 |
| Forfeited | — | — | — | — | — | — |
| Outstanding at end of period | 329,061 | $29.27 | 450,212 | $18.96 | 592,162 | $13.11 |

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.

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

| | Year Ended December 31, 2014 | | 2013 | | 2012 | |
|---|---|---|---|---|---|---|
| | 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 | 860,686 | $14.06 | 605,706 | $10.27 | 1,495,904 | $6.07 |
| Granted | 184,885 | 32.04 | 254,980 | 23.06 | 234,922 | 14.16 |
| Issued and fully vested | (370,784) | 7.81 | — | — | (1,125,120) | 5.49 |
| Forfeited | — | — | — | — | — | — |
| Outstanding at end of period | 674,787 | $22.42 | 860,686 | $14.06 | 605,706 | $10.27 |

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

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, 2014 and 2013, was $4.0 million and $7.8 million, respectively. The current portion of the liability, included in accrued liabilities in the Consolidated Balance Sheet at December 31, 2014 and 2013 was $7.0 million and $14.3 million, respectively. The Company made cash payments of $7.0 million and $18.4 million, for the years ended December 31, 2014 and 2012, respectively. There was not a cash payout associated with the TSR Performance Share Awards during 2013.

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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, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| Fair value per performance share award granted during the period | $32.04 | | $23.06 | | $14.16 | |
| Assumptions | | | | | | |
| Stock price volatility | 41.3 | % | 43.8 | % | 46.7 | % |
| Risk free rate of return | 0.7 | % | 0.4 | % | 0.4 | % |
| Expected dividend yield | 0.2 | % | 0.2 | % | 0.2 | % |

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, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Fair value per performance share award at the end of the period | $12.88 - $29.72 | $23.96 - $38.61 | $19.11 - $24.76 |
| Assumptions | | | |
| Stock price volatility | 29.1% - 29.7% | 30.2% - 35.9% | 41.1% - 45.7% |
| Risk free rate of return | 0.3% - 0.7% | 0.1% - 0.4% | 0.2% - 0.3% |
| Expected dividend yield | 0.3% | 0.2% | 0.2% |

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 (Nominal 10) 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.

Other Information

Compensation expense recorded for both the equity and liability components of all performance share awards for the years ended December 31, 2014, 2013 and 2012 was $20.8 million, $30.9 million and $24.6 million, respectively. Total unamortized compensation expense related to the equity component of performance shares at December 31, 2014 was $18.2 million and will be recognized over the next 1.9 years.

As of December 31, 2014, the aggregate intrinsic value for all performance share awards was $62.0 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2014 by the number of unvested performance share awards outstanding. As of December 31, 2014, the weighted average remaining contractual term of unvested performance share awards outstanding was approximately 0.9 years.

On December 31, 2014, the performance period ended for two types of performance share awards that were granted in 2012. 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 2015 and was certified by the Compensation Committee in February 2015. As the Company achieved the three performance metrics, 504,620 shares with a grant date fair value of $8.9 million were issued in February 2015. For the TSR Performance Share Awards, 234,922 shares with a grant date fair value of $3.3 million were issued, in addition to a cash payment of $7.0 million, based on the Company's ranking relative to a predetermined peer group. The calculation of the award payout was certified by the Compensation Committee on January 2, 2015.

Supplemental Employee Incentive Plan

The Supplemental Employee Incentive Plan (the Plan) adopted by the Company's Board of Directors is intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time, non-officer employees by providing for cash payments in the event the Company's common stock reaches a specified trading price. The Compensation Committee can increase any of the payments as applied to any employee if desired. Any deferred portion will only be paid if the participant is employed by the Company, or has terminated employment by reason of retirement, death or disability (as provided in the Plan). Payments are subject to certain other restrictions contained in the Plan.

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The Plan currently provides for a payout if the closing price per share of the Company's common stock for any 20 trading days out of any 60 days consecutive trading days equals or exceeds an interim price goal per share within two years of the effective date of the plan (interim trigger date) or a final price goal per share within four years of the effective date of the plan (final trigger date). Under the Plan and upon approval by the Compensation Committee, each eligible employee may receive a distribution of 20% of base salary if the interim trigger is met or 50% of base salary if the final trigger is met (or an incremental 30% of base salary if the interim trigger was previously achieved). In accordance with the Plan, in the event either the interim or final trigger date occurs within the first 30 months from the effective date, 25% of the total distribution will be paid immediately and the remaining 75% will be deferred and paid at a future date as described in the Plan. For final trigger dates occurring during the last 18 months but before the end of the Plan, total distribution will be paid immediately.

The Plan is accounted for as a liability award under the authoritative accounting guidance for stock-based compensation and is valued as of the end of each reporting period on a mark-to-market basis using a Monte Carlo simulation model. In addition to the expected value of plan payouts, the simulation technique also generates an expected trigger date for the two types of payments made under this plan, which is used to determine the requisite service period. The Company recognized compensation expense of $3.0 million, $11.5 million and $1.4 million for years ended December 31, 2014, 2013 and 2012, respectively, related to the Plan. The Company made payments under the Plan of $13.0 million and $4.5 million for years ended December 31, 2014 and 2013, respectively. There were no payments made under the Plan for the year ended December 31, 2012.

SEIP II. Supplemental Employee Incentive Plan II (SEIP II) expired on June 30, 2012 and there were no amounts paid under the expired plan.

SEIP III. On May 1, 2012, the Company's Board of Directors adopted the Supplemental Employee Incentive Plan III (SEIP III) to replace the SEIP II with an effective date of July 1, 2013. The SEIP III provides for a payout under the Plan if the closing price per share of the Company's common stock equals or exceeds the price goal of $25.00 per share by June 30, 2014 (interim trigger date) or $37.50 per share by June 30, 2016 (final trigger date).

On February 11, 2013, the Company achieved the price goal of $25.00 per share prior to the interim trigger date. Accordingly, a total distribution of approximately $6.8 million was earned by the Company's eligible employees under the Plan, of which 25% of the total distribution, or $1.7 million, was paid in February 2013 and the remaining 75%, or $4.9 million, was paid in August 2014 in accordance with the SEIP III.

On August 27, 2013, the Company achieved the price goal of $37.50 per share prior to the final trigger date. Accordingly, a total distribution of approximately $11.1 million was earned by the Company's eligible employees under the Plan, of which 25% of the total distribution, or $2.8 million, was paid in September 2013 and the remaining 75%, or $8.1 million, was paid in August 2014 in accordance with the SEIP III.

SEIP IV. On September 19, 2013, the Company's Board of Directors adopted the Supplemental Employee Incentive Plan IV (SEIP IV) to replace the SEIP III with an effective date of October 1, 2013. The SEIP IV provides for a payout under the Plan if the closing price per share of the Company's common stock equals or exceeds the price goal of $55.00 per share by September 30, 2015 (interim trigger date) or $80.00 per share by September 30, 2017 (final trigger date).

The following assumptions were used to determine the fair value of the SEIP III and SEIP IV liabilities at the end of the respective periods:

| | December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Valuation Assumptions | | | |
| Stock price volatility | 33.4 % | 38.0 % | 39.5 % |
| Risk free rate of return | 1.0 % | 1.1 % | 0.5 % |
| Annual salary increase rate | 4.0 % | 4.0 % | 4.0 % |
| Annual turnover rate | 4.6 % | 4.6 % | 6.1 % |

Deferred Performance Shares

As of December 31, 2014, 534,174 shares of the Company's common stock representing vested performance share awards were deferred into the deferred compensation plan. No shares were sold out of the plan in 2014. During 2014, a decrease to the deferred compensation liability of $4.3 million was recognized, representing a decrease in the Company's

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common stock held in the rabbi trust from December 31, 2013 to December 31, 2014. The decrease in compensation expense was included in general and administrative expense in the Consolidated Statement of Operations.

14. Earnings per Common Share

Basic EPS is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated except that the denominator 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 vested at the end of the applicable period.

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

| | December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Weighted-average shares—basic | 415,840 | 420,188 | 419,075 |
| Dilution effect of stock appreciation rights and stock awards at end of period | 1,761 | 2,187 | 2,912 |
| Weighted-average shares—diluted | 417,601 | 422,375 | 421,987 |
| Weighted-average shares excluded from diluted earnings per share due to the anti-dilutive effect | 20 | 5 | 85 |

15. Accumulated Other Comprehensive (Loss)

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

| (In thousands) | Net Gains (Losses) on Cash Flow Hedges | Defined Benefit Pension and Postretirement Benefits | Total |
|---|---|---|---|
| Balance at December 31, 2011 | $121,358 | $(16,811) | $104,547 |
| Other comprehensive income (loss) before reclassifications | 53,815 | 1,258 | 55,073 |
| Amounts reclassified from accumulated other comprehensive income (loss) | (144,456) | 8,716 | (135,740) |
| Net current-period other comprehensive income (loss) | $(90,641) | $9,974 | $(80,667) |
| Balance at December 31, 2012 | $30,717 | $(6,837) | $23,880 |
| Other comprehensive income (loss) before reclassifications | (2,720) | 4,641 | 1,921 |
| Amounts reclassified from accumulated other comprehensive income (loss) | (34,548) | 386 | (34,162) |
| Net current-period other comprehensive income (loss) | (37,268) | 5,027 | (32,241) |
| Balance at December 31, 2013 | $(6,551) | $(1,810) | $(8,361) |
| Other comprehensive income (loss) before reclassifications | (80,175) | (325) | (80,500) |
| Amounts reclassified from accumulated other comprehensive income (loss) | 86,726 | (16) | 86,710 |
| Net current-period other comprehensive income (loss) | 6,551 | (341) | 6,210 |
| Balance at December 31, 2014 | $— | $(2,151) | $(2,151) |

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

| (In thousands) | Year Ended December 31, 2014 | 2013 | 2012 | Affected Line Item in the Condensed Consolidated Statement of Operations |
|---|---|---|---|---|
| Net Gains (Losses) on Cash Flow Hedges | | | | |
| Commodity contracts | $(143,577) | $52,733 | $225,108 | Natural gas revenues |
| Commodity contracts | (626) | 4,269 | 11,218 | Crude oil and condensate revenues |
| Defined Benefit Pension and Postretirement Benefits | | | | |
| Amortization of prior service cost | — | — | (221) | General and administrative expense |
| Amortization of net (gain) loss | 26 | (641) | (13,906) | General and administrative expense |
| | (144,177) | 56,361 | 222,199 | Total before tax |
| | 57,467 | (22,199) | (86,459) | Tax expense |
| Total reclassifications for the period | $(86,710) | $34,162 | $135,740 | Net of tax |

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16. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

| | December 31, | |
|---|---|---|
| (In thousands) | 2014 | 2013 |
| Accounts receivable, net | | |
| Trade accounts | $227,835 | $215,361 |
| Joint interest accounts | 2,245 | 7,261 |
| Income taxes receivable | 3,612 | 922 |
| Other accounts | 6,515 | 746 |
| | 240,207 | 224,290 |
| Allowance for doubtful accounts | (1,198) | (1,814) |
| | $239,009 | $222,476 |
| Inventories | | |
| Natural gas in storage | $3,281 | $9,056 |
| Tubular goods and well equipment | 10,675 | 8,396 |
| Other accounts | 70 | 16 |
| | $14,026 | $17,468 |
| Other current assets | | |
| Prepaid balances and other | 1,855 | 2,587 |
| | $1,855 | $2,587 |
| Other assets | | |
| Deferred compensation plan | $13,115 | $12,507 |
| Debt issuance cost | 17,349 | 16,476 |
| Other accounts | 65 | 79 |
| | $30,529 | $29,062 |
| Accounts payable | | |
| Trade accounts | 54,949 | 26,023 |
| Natural gas purchases | 2,407 | 2,052 |
| Royalty and other owners | 97,298 | 79,150 |
| Accrued capital costs | 222,426 | 146,899 |
| Taxes other than income | 16,806 | 13,677 |
| Drilling advances | 88 | 14,093 |
| Other accounts | 6,102 | 6,907 |
| | $400,076 | $288,801 |
| Accrued liabilities | | |
| Employee benefits | $22,815 | $43,599 |
| Taxes other than income | 7,128 | 6,894 |
| Interest payable | 30,677 | 20,211 |
| Other accounts | 3,049 | 2,897 |
| | $63,669 | $73,601 |
| Other liabilities | | |
| Deferred compensation plan | $28,932 | $33,211 |
| Other accounts | 10,675 | 13,043 |
| | $39,607 | $46,254 |

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17. Supplemental Cash Flow Information

Cash paid for interest and income taxes are as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (In thousands) | 2014 | 2013 | 2012 |
| Interest | $58,487 | $63,279 | $64,970 |
| Income taxes | 77,029 | 35,281 | 22,501 |

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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, 2014, 2013 and 2012 were based on studies performed by the Company's petroleum engineering staff. The estimates were computed using the 12-month average crude oil and natural gas index prices, 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, 2014, 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 in 2014, 2013 and 2012.

| | Natural Gas (Bcf) | Crude Oil & NGLs (Mbbl)(1) | Total (Bcfe)(2) |
|---|---|---|---|
| December 31, 2011 | 2,910 | 20,470 | 3,033 |
| Revision of prior estimates(3) | 207 | (3,101) | 189 |
| Extensions, discoveries and other additions(4) | 869 | 9,628 | 926 |
| Production | (253) | (2,407) | (268) |
| Sales of reserves in place | (37) | (216) | (38) |
| December 31, 2012 | 3,696 | 24,374 | 3,842 |
| Revision of prior estimates(5) | 435 | (419) | 433 |
| Extensions, discoveries and other additions(4) | 1,661 | 10,683 | 1,725 |
| Production | (394) | (3,221) | (414) |
| Sales of reserves in place(6) | (103) | (4,879) | (132) |
| December 31, 2013 | 5,295 | 26,538 | 5,454 |
| Revision of prior estimates(7) | 483 | 1,688 | 493 |
| Extensions, discoveries and other additions(4) | 1,807 | 17,223 | 1,911 |
| Production | (508) | (3,961) | (532) |
| Purchases of reserves in place(8) | 7 | 11,778 | 77 |
| Sales of reserves in place | (2) | (130) | (2) |
| December 31, 2014 | 7,082 | 53,136 | 7,401 |
| Proved Developed Reserves | | | |
| December 31, 2011 | 1,734 | 10,922 | 1,800 |
| December 31, 2012 | 2,216 | 12,828 | 2,293 |
| December 31, 2013 | 3,147 | 13,652 | 3,228 |
| December 31, 2014 | 4,339 | 27,221 | 4,502 |
| Proved Undeveloped Reserves | | | |
| December 31, 2011 | 1,176 | 9,548 | 1,233 |
| December 31, 2012 | 1,480 | 11,546 | 1,549 |
| December 31, 2013 | 2,148 | 12,886 | 2,226 |
| December 31, 2014 | 2,743 | 25,915 | 2,898 |

(1) NGL reserves were less than 1.0% of our total proved equivalent reserves for 2014, 2013 and 2012, and 13.5%, 12.3% and 8.7% of our proved crude oil and NGL reserves for 2014, 2013 and 2012, 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 188.6 Bcfe was primarily due to an upward performance revision of 369.6 Bcfe, primarily in the Dimock field in northeast Pennsylvania, partially offset by (i) a downward revision of 114.5 Bcfe associated with commodity pricing and (ii) a downward revision of 66.5 Bcfe of proved undeveloped reserves that are no longer in our five-year development plan.

(4) Extensions, discoveries and other additions were primarily related to drilling activity in the Dimock field located in northeast Pennsylvania. The Company added 1,797.8 Bcfe, 1,653.3 Bcfe and 860.6 Bcfe of proved reserves in this field in 2014, 2013 and 2012, respectively.

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(5) The net upward revision of 432.8 Bcfe was primarily due to (i) an upward performance revision of 372.6 Bcfe, primarily in the Dimock field in northeast Pennsylvania and (ii) an upward revision of 60.2 Bcfe associated with commodity pricing.

(6) Sales of reserves in place were primarily related to the divestiture of certain oil and gas properties in Oklahoma and west Texas in December 2013 which represented 132.3 Bcfe.

(7) The net upward revision of 493.0 Bcfe was primarily due to (i) an upward performance revision of 492.1 Bcfe, primarily in the Dimock field in northeast Pennsylvania and (ii) an upward revision of 0.9 Bcfe associated with commodity pricing.

(8) Purchases of reserves in place were primarily related to the acquisition of certain oil and gas properties in the Eagle Ford Shale in October and December 2014 which represented 77 Bcfe.

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) | 2014 | 2013 | 2012 |
| Aggregate capitalized costs relating to oil and gas producing activities | $8,811,624 | $7,059,200 | $6,507,137 |
| Aggregate accumulated depreciation, depletion and amortization | (3,893,772) | (2,518,003) | (2,200,061) |
| Net capitalized costs | $4,917,852 | $4,541,197 | $4,307,076 |

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) | 2014 | 2013 | 2012 |
| Property acquisition costs, proved | $214,737 | $— | $— |
| Property acquisition costs, unproved | 73,962 | 71,234 | 88,880 |
| Exploration costs | 36,306 | 44,906 | 59,198 |
| Development costs | 1,446,728 | 1,069,965 | 821,806 |
| Total costs | $1,771,733 | $1,186,105 | $969,884 |

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.

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Under the Standardized Measure, future cash inflows for 2014, 2013 and 2012 were estimated by using the 12-month average crude oil and natural gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during the year.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Natural gas | $3.52 | $3.58 | $2.83 |
| Crude oil | $93.32 | $101.17 | $102.02 |
| NGLs | $30.40 | $28.11 | $37.88 |

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) | 2014 | 2013 | 2012 |
| Future cash inflows | $29,432,733 | $21,383,701 | $12,826,877 |
| Future production costs | (8,620,320) | (5,895,024) | (4,300,025) |
| Future development costs | (2,689,406) | (1,863,534) | (1,614,878) |
| Future income tax expenses | (5,635,790) | (4,398,348) | (1,873,185) |
| Future net cash flows | 12,487,217 | 9,226,795 | 5,038,789 |
| 10% annual discount for estimated timing of cash flows | (5,994,211) | (4,527,262) | (2,302,934) |
| Standardized measure of discounted future net cash flows | $6,493,006 | $4,699,533 | $2,735,855 |

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) | 2014 | 2013 | 2012 |
| Beginning of year | $4,699,533 | $2,735,855 | $3,158,726 |
| Discoveries and extensions, net of related future costs | 2,306,779 | 2,082,983 | 911,044 |
| Net changes in prices and production costs | (200,399) | 1,320,490 | (1,682,131) |
| Accretion of discount | 625,092 | 313,420 | 400,091 |
| Revisions of previous quantity estimates | 535,904 | 478,409 | 139,540 |
| Timing and other | 18,225 | 114,947 | (243,688) |
| Development costs incurred | 414,469 | 340,500 | 282,476 |
| Sales and transfers, net of production costs | (1,539,693) | (1,258,094) | (636,633) |
| Net purchases (sales) of reserves in place | 209,484 | (275,926) | (37,412) |
| Net change in income taxes | (576,388) | (1,153,051) | 443,842 |
| End of year | $6,493,006 | $4,699,533 | $2,735,855 |

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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 |
|---|---|---|---|---|---|
| 2014 | | | | | |
| Operating revenues | $509,803 | $533,187 | $512,017 | $618,004 | $2,173,011 |
| Impairment of oil and gas properties[1] | — | — | — | 771,037 | 771,037 |
| Operating income[2] | 194,487 | 210,653 | 190,341 | (489,295) | 106,186 |
| Net income[2] | 107,031 | 118,420 | 100,788 | (221,771) | 104,468 |
| Basic earnings per share | 0.26 | 0.28 | 0.24 | (0.53) | 0.25 |
| Diluted earnings per share | 0.26 | 0.28 | 0.24 | (0.53) | 0.25 |
| 2013 | | | | | |
| Operating revenues | $373,285 | $449,680 | $435,850 | $487,463 | $1,746,278 |
| Operating income[3] | 87,014 | 165,026 | 131,810 | 167,732 | 551,582 |
| Net income[3] | 42,824 | 89,114 | 69,889 | 77,946 | 279,773 |
| Basic earnings per share | 0.10 | 0.21 | 0.17 | 0.19 | 0.67 |
| Diluted earnings per share | 0.10 | 0.21 | 0.17 | 0.19 | 0.66 |

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

(2) Operating income and net income include a $19.9 million gain on the disposition of certain of proved and unproved oil and gas properties located in east Texas in the fourth quarter.

(3) Operating income and net income include a $19.4 million gain on the disposition of certain of proved and unproved oil and gas properties located in the Oklahoma and Texas panhandles in the fourth quarter, partially offset by a $17.5 million loss on sale of certain proved and unproved oil and gas properties located in Oklahoma, Texas and Kansas properties in the fourth quarter. Various other proved and unproved properties were sold during the year for a net gain of $19.5 million.

## 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, 2014, 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.

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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, 2014. 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, 2014, 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, 2014, 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 2015 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 2015 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 2015 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 2015 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 2015 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 53.

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 |
|---|---|
| 3.1 | Restated Certificate of Incorporation of the Company (Form 8-K for January 21, 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, effective as of February 17, 2012 (Form 10-Q for the quarter ended June 30, 2012). |
| 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 26, 2001 among Cabot Oil & Gas Corporation and the Purchasers listed therein (Form 8-K for August 30, 2001). |
| | (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 September 28, 2010 (Form 10-Q for the quarter ended September 30, 2010). |
| 4.3 | Note Purchase Agreement dated as of July 16, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K for July 16, 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). |
| 4.4 | 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). |
| 4.5 | Note Purchase Agreement dated as of December 30, 2010 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 10-K for 2010). |
| 4.6 | Note Purchase Agreement dated as of September 18, 2014 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K for September 24, 2014). |
| *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). |

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| | |
|---|---|
| *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). |
| 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 | Savings Investment Plan of the Company, as amended and restated effective January 1, 2009 (Form 10-K for 2009). |
| | (a) First Amendment to the Savings Investment Plan of the Company effective October 1, 2010 (Form 10-K for 2010). |
| *10.11 | Nonemployee Director Deferred Compensation Plan effective December 21, 2012 (Form 10-K for 2012). |
| 10.12 | 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). |
| 10.13 | 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). |
| 10.14 | 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). |
| 10.15 | 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. |

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| 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.

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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 27th of February 2015.

CABOT OIL & GAS CORPORATION

By: /s/ DAN O. DINGES
Dan O. Dinges
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ DAN O. DINGES<br>Dan O. Dinges | Chairman, President and Chief Executive Officer (Principal Executive Officer) | February 27, 2015 |
| /s/ SCOTT C. SCHROEDER<br>Scott C. Schroeder | Executive Vice President and Chief Financial Officer (Principal Financial Officer) | February 27, 2015 |
| /s/ TODD M. ROEMER<br>Todd M. Roemer | Controller (Principal Accounting Officer) | February 27, 2015 |
| /s/ RHYS J. BEST<br>Rhys J. Best | Director | February 27, 2015 |
| /s/ JAMES R. GIBBS<br>James R. Gibbs | Director | February 27, 2015 |
| /s/ ROBERT L. KEISER<br>Robert L. Keiser | Director | February 27, 2015 |
| /s/ ROBERT KELLEY<br>Robert Kelley | Director | February 27, 2015 |
| /s/ P. DEXTER PEACOCK<br>P. Dexter Peacock | Director | February 27, 2015 |
| /s/ W. MATT RALLS<br>W. Matt Ralls | Director | February 27, 2015 |