CABOT OIL & GAS CORP
Form 10-K
February 28, 2014

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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, 2013

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 o (Do not check if a smaller reporting company)	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 28, 2013) was approximately $14.9 billion.

As of February 14, 2014, there were 422,239,090 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 1, 2014 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.

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

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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.

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 properties.

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

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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.

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.

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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.

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 High-Return, 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. 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, high-return 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 select asset sales, joint ventures and borrowings under our credit facility.

Continued Portfolio Management. We will continue to evaluate and manage our properties that no longer fit in our current portfolio through the execution of strategic asset sales or other similar arrangements. We expect to utilize the proceeds generated from these activities for reinvestment into higher-return projects in our core operating areas, potential share repurchases or new growth initiatives.

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.

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2014 OUTLOOK

In 2014, we plan to spend between approximately $1.3 billion and $1.4 billion on capital and exploration activities. We plan to drill approximately 155 to 175 gross wells (or 150 to 170 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 73% of our 2014 capital program to the Marcellus Shale, approximately 25% to our oil-focused play in the Eagle Ford Shale and the remaining 2% to other emerging plays and non-drilling expenditures. Incremental to our capital and exploration expenditures program, we also expect to contribute approximately $36.4 million to Constitution Pipeline Company, LLC (Constitution) to fund costs associated with the development and construction of a natural gas pipeline in northeast Pennsylvania. See Note 4 of the Notes to the Consolidated Financial Statements for further details regarding our investment in Constitution.

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 Bradford and Wyoming Counties, Pennsylvania. We currently hold approximately 200,000 net acres in the dry gas window of the play. Our 2013 net production in the Marcellus Shale was 356.5 Bcfe, representing approximately 86% of our total equivalent production for the year. As of December 31, 2013, we had a total of 354.6 net wells in the Marcellus Shale, the majority of which are operated by us.

During 2013, we invested $815.8 million in the Marcellus Shale and drilled 94.5 net horizontal wells and completed and turned in line 96.0 net wells. As of December 31, 2013, we had 30.0 net wells that were either in the completion stage or waiting on completion or connection to a pipeline. We exited 2013 with six drilling rigs operating in the play.

Eagle Ford Shale

Our properties in the Eagle Ford Shale are principally located in Atascosa, Frio, La Salle and Zavala Counties, Texas where we hold over 60,000 net acres in the oil window of the play. In 2013, our net crude oil/condensate/NGL and natural gas production from the Eagle Ford was 2,164 Mbbl and 1.2 Bcf, respectively, or 14.2 Bcfe, representing approximately 3% of our full year equivalent production. As of December 31, 2013, we had a total of 85.4 net wells in the Eagle Ford.

During 2013, we invested $261.5 million in the Eagle Ford and drilled or participated in drilling 33.2 net wells. We exited 2013 with two drilling rigs operating in the play.

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 Pearsall Shale in south Texas; the Cotton Valley, Haynesville, Bossier, and James Lime formations in east Texas; the Devonian Shale, Big Lime, Weir and Berea in West Virginia; and the Frio, Vicksburg and Wilcox formations in south Texas.

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In 2013, we invested $19.0 million in the Pearsall Shale and drilled a total of 11.1 net wells under a joint development agreement with a wholly owned subsidiary of Osaka Gas Co., Ltd. (Osaka) that was entered into in June 2012. Under the joint development agreement, Osaka agreed to fund 85% of our share of drilling and completion costs associated with these leaseholds. The drilling and completion carry of $125.0 million was fully satisfied in fourth quarter 2013.

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 five local distribution companies and numerous end users as of the end of 2013. 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.

DIVESTITURES

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, subject to post closing adjustments, 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, subject to post closing adjustments, and recognized a $17.5 million loss on sale of assets.

In 2013, we sold various other proved and unproved 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 for $125.0 million and recognized a $67.0 million gain on sale of assets.

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

In October 2011, we sold certain proved oil and gas properties located in Colorado, Utah and Wyoming to BreitBurn Energy Partners, L.P. for $285.0 million and recognized a $4.2 million gain on sale of assets.

In May 2011, we sold certain of our unproved Haynesville and Bossier Shale oil and gas properties in east Texas to a third party for approximately $47.0 million and recognized a $34.2 million gain on sale of assets.

In 2011, we sold various other unproved properties and other assets for approximately $73.5 million and recognized an aggregate net gain of $25.0 million.

In December 2010, we sold our existing Pennsylvania gathering infrastructure of approximately 75 miles of pipeline and two compressor stations to Williams Field Services (Williams), a subsidiary of Williams Partners L.P., for $150 million and recognized a $49.3 million gain on sale of assets.

In 2010, we sold various other proved and unproved properties and other assets for approximately $32.2 million and recognized an aggregate net gain of $16.3 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.

In February 2014, we entered into a Precedent Agreement with Transcontinental Gas Pipe Line Company, LLC (Transco) for the construction of a new pipeline with committed takeaway capacity from our acreage position in Susquehanna Country, Pennsylvania. Under the terms of the Precedent Agreement, Transco will construct and operate approximately 177 miles of new pipeline from the Zick area of Susquehanna County to an interconnect with Transco's mainline in Lancaster County, Pennsylvania. We will own 850,000 MMBtu per day of firm capacity on the newly constructed pipeline and acquire a 20% equity interest in the project, subject to certain terms and conditions yet to be determined and regulatory approval. The expected in-service date for the new pipeline is scheduled for the second half of 2017. In February 2014, we also entered into a definitive Gas Sale and Purchase Agreement with WGL Midstream, Inc. (WGL) to sell 500,000 MMBtu per day of natural gas to WGL for a primary term of 15 years, commencing upon the in-service date of the newly constructed pipeline.

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 and 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 2013, natural gas collars with floor prices ranging from $3.09 to $5.15 per Mcf and ceiling prices ranging from $3.98 to $6.23 per Mcf covered 241.7 Bcf, or 61%, of our natural gas production at an average price of $3.96 per Mcf. Crude oil swaps covered 1,095 Mbbl, or 38% of our crude oil production at an average price $101.90 per Bbl.

As of December 31, 2013, we had the following outstanding commodity derivatives designated as hedging instruments:

			Collars				Swaps
			Floor		Ceiling		
Type of Contract	**Volume**	**Contract Period**	**Range**	**Weighted-Average**	**Range**	**Weighted-Average**	**Weighted-Average**
Natural gas	336.8 Bcf	Jan. 2014 - Dec. 2014	$3.60 - $4.37	$ 4.13	$4.22 - $4.80	$ 4.51	
Natural gas	35.5 Bcf	Jan. 2014 - Dec. 2014					$ 4.12

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.

RESERVES

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

	December 31,		
	2013	**2012**	**2011**
Natural Gas *(Bcf)*			
Proved developed reserves	3,147	2,216	1,734
Proved undeveloped reserves[1]	2,148	1,480	1,176
	5,295	3,696	2,910
Crude Oil & NGLs *(Mbbl)*			
Proved developed reserves	13,652	12,828	10,922
Proved undeveloped reserves[1]	12,886	11,546	9,548
	26,538	24,374	20,470
Natural gas equivalent *(Bcfe)*[2]	5,454	3,842	3,033
Reserve life *(in years)*[3]	13.2	14.4	16.2

(1) *Proved undeveloped reserves for 2013, 2012 and 2011 include reserves drilled but awaiting completion of 239.1 Bcfe, 153.3 Bcfe and 132.4 Bcfe, respectively.*

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

(3) *Reserve life index is equal to year-end proved reserves divided by annual production for the years ended December 31, 2013, 2012 and 2011, respectively.*

Our proved reserves totaled approximately 5,454 Bcfe at December 31, 2013, of which 97% were natural gas. This reserve level was up by 42% from 3,842 Bcfe at December 31, 2012. In 2013, we added 1,724.7 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 432.8 Bcfe, which was primarily due to an upward performance revision of 372.6 Bcfe, primarily in the Dimock field in northeast Pennsylvania and an upward revision of 60.2 Bcfe associated with commodity pricing. In 2013, we produced 413.6 Bcfe and sold 132.3 Bcfe associated with the divestiture of oil and gas properties in Oklahoma and west 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 2013, 2012 and 2011, respectively. 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 several different 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.

Internal Control

Our Vice President, Engineering and Technology is the technical person primarily responsible for our internal reserves estimation process and provides oversight of our corporate reservoir engineering department, which consists of four professional 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 31 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 22 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 Vice President, Chief Financial Officer and Treasurer, 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

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reserves estimation processes were comprehensive and of sufficient depth, (3) the data upon which we relied were adequate and of sufficient quality, and (4) the results of our estimates and projections are, in the aggregate, reasonable. A copy of the audit letter by Miller and Lents dated January 23, 2014, 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, 2013 we had 2,225.8 Bcfe of proved undeveloped (PUD) reserves with future development costs of $1.6 billion, which represents an increase of 676.6 Bcfe compared with December 31, 2012. As of December 31, 2013, 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, 2013
Balance at beginning of period	1,549
Transfers to proved developed	(561)
Additions	951
Revision of prior estimates	291
Sales of reserves in place	(4)
Balance at end of period	2,226

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

- transfer of 561.2 Bcfe from PUD to proved developed reserves based on total capital expenditures of $449.5 million during 2013;
- new PUD reserve additions of 950.6 Bcfe primarily in the Dimock field in northeast Pennsylvania;
- positive PUD reserve revisions of 291.2 Bcfe resulting from positive performance revisions of 295.5 Bcfe, primarily in the Dimock field in northeast Pennsylvania, offset by negative price revisions of 4.3 Bcfe; and
- sales of reserves in place of 4.0 Bcfe, primarily in Oklahoma.

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PRODUCTION, SALES PRICE AND PRODUCTION COSTS

The following table presents historical information about our production volumes for natural gas and crude oil (including condensate and 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,		
	2013	2012	2011
Production Volumes			
Natural gas *(Bcf)*			
Dimock field	356.5	209.3	119.3
Total	394.2	253.2	178.8
Crude oil (Mbbl)[1]			
Total	3,221	2,407	1,443
Equivalents *(Bcfe)*			
Dimock field	356.5	209.3	119.3
Total	413.6	267.7	187.5
Natural Gas Average Sales Price *($/Mcf)*			
Dimock field	$ 3.48	$ 2.82	$ 3.85
Total (excluding realized impact of derivative settlements)	$ 3.43	$ 2.79	$ 3.99
Total (including realized impact of derivative settlements)	$ 3.56	$ 3.67	$ 4.46
Crude Oil Average Sales Price *($/Bbl)*			
Total (excluding realized impact of derivative settlements)	$ 99.65	$ 96.65	$ 89.48
Total (including realized impact of derivative settlements)	$ 101.13	$ 101.65	$ 90.49
Average Production Costs *($/Mcfe)*			
Dimock field	$ 0.06	$ 0.08	$ 0.09
Total	$ 0.27	$ 0.37	$ 0.47

(1) *Includes NGLs which represent less than 1% of our equivalent production for all years presented and 10.5%, 6.9% and 3.6%, of our crude oil production for the years ended December 31, 2013, 2012 and 2011, 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, 2013. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	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, 2013 is 67,234, 109,948 and 34,894 for the years ending December 31, 2014, 2015 and 2016, 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, 2013, approximately 38% 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, 2013. This summary includes natural gas and crude oil wells in which we have a working interest.

	Gross	**Net**
Natural Gas	4,212	3,791.1
Crude Oil	173	125.2
Total[1]	4,385	3,916.3

(1) *Total percentage of gross operated wells is 91.5%.*

DRILLING ACTIVITY

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

	Year Ended December 31,					
	2013		**2012**		**2011**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development Wells						
Productive	169	145.4	149	102.7	149	86.0
Dry	2	1.3				
Extension Wells						
Productive			8	7.0	7	5.5
Dry						
Exploratory Wells						
Productive	9	6.8	9	6.3	4	3.5
Dry	1		4	1.8	1	1.0
Total	181	153.5	170	117.8	161	96.0

At December 31, 2013, 9 gross (9.0 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, often little investigation of record title is made at the time of lease acquisition. 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, 2013 and 2012, 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. During the year ended December 31, 2011, we did not have any one customer account for greater than 10% 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.

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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.

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.

Additionally, in 2012 we executed a precedent agreement with Constitution Pipeline Company, LLC, at the time a wholly owned subsidiary of Williams Partners L.P., for transportation 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 120-mile pipeline project that, once completed, will provide 650,000 Dth per day of pipeline capacity. FERC has scheduled issuance of the project's final environmental impact statement for June 13, 2014. There is no guarantee that FERC will certify the project or, if they do, that the project scope or timeline for construction will remain unchanged by the regulatory permitting process. If placed into service, the project pipeline will be an interstate pipeline subject to full regulation by FERC under the NGA.

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 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

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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 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.

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 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.

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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 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.

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 level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities. For additional information about hydraulic fracturing and related environmental matters, please read "Risk Factors Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays" in Item 1A.

Greenhouse Gas. In response to recent 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, almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA has also begun to regulate carbon dioxide and other greenhouse gas emissions under existing provisions of the Clean Air Act. 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.

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Employees

As of December 31, 2013, we had 684 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 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, Code of Business Conduct, Audit Committee Charter, Corporate Governance and Nominations Committee Charter, Compensation Committee Charter 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 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. Depressed prices in the future would have a negative impact on our future financial results and could result in an impairment charge. See "Future natural gas and oil price declines may result in write-downs of the carrying amount of our assets, which could materially and adversely affect our results of operations." Because our reserves are predominantly natural gas, changes in natural gas prices have a more significant impact on our financial results.

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;

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- 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;
- 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 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;

compliance with, or changes in, governmental requirements and regulation; and

costs of shortages or delays in the availability of drilling rigs or crews and the delivery of equipment and materials.

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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.

Future natural gas and oil price declines may result in 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 crude oil. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make material downward adjustments to our estimated proved reserves, and could result in an impairment charge and a corresponding write-down of the carrying amount of our oil and natural gas properties.

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.

Our reserve report estimates that production from our proved developed reserves as of December 31, 2013 will increase at an estimated rate of 0.5% during 2014 and then decline at estimated rates of 36%, 24% and 18% during 2015, 2016 and 2017, 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 2014 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 2014 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, 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

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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 2011-2016 National Enforcement Initiative, "Assuring 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 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.

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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, 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, 2013, we owned or operated approximately 3,100 miles of natural gas gathering and pipeline systems. As part of our normal maintenance program,

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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. Non-operated wells represented approximately 8.5% of our total owned gross wells, or approximately 2.5% of our owned net wells, as of December 31, 2013. 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.

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 that 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.

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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 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 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 hedging 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 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 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, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate a rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. The EPA expects to issue an Advance Notice of Proposed Rulemaking in August 2014. Further, on May 24, 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. 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 Railroad Commission of Texas adopted rules in December 2011 requiring disclosure of

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certain information regarding the components used in the hydraulic fracturing process. 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 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. 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 2014. 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 2014. 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. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

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.

There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of greenhouse gases. In the United States, climate change action is evolving at the state, regional and federal levels. On December 17, 2010, the EPA amended the "Mandatory Reporting of Greenhouse Gases" final rule ("Reporting Rule") originally issued in September 2009. The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gases emissions annually on a facility-by-facility basis. In addition, on December 15, 2009, the EPA published a Final Rule finding that current and projected

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concentrations of six key greenhouse gases in the atmosphere threaten public health and the welfare of current and future generations. The EPA also found that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to pollution that threatens public health and welfare. This Final Rule, also known as the EPA's Endangerment Finding, does not impose any requirements on industry or other entities directly. However, following issuance of the Endangerment Finding, EPA promulgated final motor vehicle GHG emission standards on April 1, 2010, the effect of which could reduce demand for motor fuels refined from crude oil. On June 3, 2010, EPA issued a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi step process, with the largest sources first subject to permitting. In addition, on November 8, 2010, EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year were required to report annual GHG emissions to EPA, for the first time by September 28, 2012. We submitted our report in compliance with the deadline.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases. While it is not possible at this time to predict how regulation or legislation that may be enacted to address greenhouse gases emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

Moreover, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for greenhouse gases, became binding on all those countries that had ratified it. Ongoing international discussions following the United Nations Climate Change Conference in Warsaw Poland in November 2013 are exploring options to reduce global emissions by the first quarter of 2015.

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

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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.

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.

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Environmental Matters

The information set forth under the heading "Environmental 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.

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.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 20, 2014 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	60	Chairman, President and Chief Executive Officer	2001
Scott C. Schroeder	51	Executive Vice President, Chief Financial Officer and Treasurer	1997
Jeffrey W. Hutton	58	Senior Vice President, Marketing	1995
G. Kevin Cunningham	60	Vice President, General Counsel	2010
Robert G. Drake	66	Vice President, Information Services and Operational Accounting	1998
Todd L. Liebl	56	Vice President, Land and Business Development	2012
Steven W. Lindeman	53	Vice President, Engineering and Technology	2011
James M. Reid	62	Vice President, Regional Manager South Region	2009
Phillip L. Stalnaker	54	Vice President, Regional Manager North Region	2009
Todd M. Roemer	43	Controller	2010
Deidre L. Shearer	46	Corporate Secretary and Managing Counsel	2012

All officers are elected annually by our Board of Directors. All of the executive officers have been employed by Cabot Oil & Gas Corporation for at least the last five years, except for Mr. G. Kevin Cunningham, Mr. Todd M. Roemer and Ms. Deidre L. Shearer.

Mr. Cunningham joined the Company in November 2009 as Associate General Counsel and was appointed General Counsel in September 2010 and promoted to Vice President in 2011. Prior to joining the Company, Mr. Cunningham was Regional Counsel-Southern Division at Chesapeake Energy from 2006 until November 2009. He is a graduate of the University of Texas School of Law and has worked at Fortune 500 E&P companies in both legal and business positions since 1982.

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.

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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.

On July 23, 2013, the Board of Directors declared a 2-for-1 split of our common stock in the form of a stock dividend. The stock dividend was distributed on August 14, 2013 to shareholders of record on August 6, 2013. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of our common stock.

	High	Low	Dividends
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
2012			
First Quarter	$ 20.68	$ 15.13	$ 0.01
Second Quarter	$ 20.62	$ 14.77	$ 0.01
Third Quarter	$ 22.93	$ 19.49	$ 0.01
Fourth Quarter	$ 25.54	$ 21.47	$ 0.01

As of February 3, 2014, there were 426 registered holders of our common stock.

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EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2013 regarding the number of shares of common stock that may be issued under our 2004 Incentive Plan, which is the only equity compensation plan with awards outstanding. The 2004 Incentive Plan was approved by our stockholders.

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	4,202,963(1)	$ 12.63(2)	1,731,635(3)
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	4,202,963	$ 12.63	1,731,635

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(1) *Includes 667,764 SARs to be settled in common stock which vest, if at all, in 2014 and 2015; 1,657,980 employee performance shares, the performance periods of which end on December 31,2013, 2014 and 2015; 860,686 TSR performance shares, the performance periods of which end on December 31, 2013, 2014 and 2015; 450,212 hybrid performance shares, of which vest, if at all, in 2014, 2015, and 2016; and 566,321 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) *27,806 shares of restricted stock, the restrictions on which lapse on various dates in 2014, 2015 and 2016; and 1,703,829 shares that are available for future grants under the 2004 Incentive Plan. On April 29, 2014, the 2004 Incentive Plan expires and no additional shares may be granted under the 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, 2013.

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 2013		$		19,181,200
November 2013	3,952,547	$ 34.19	3,952,547	15,228,653

December 2013	856,819	$	34.31	856,819	14,371,834
Total	4,809,366			4,809,366	14,371,834

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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 2008 through December 2013. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2008 and that all dividends were reinvested.

	December 31,					
Calculated Values	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
COG	$ 100.00	$ 168.25	$ 146.61	$ 294.63	$ 386.95	$ 604.13
S&P 500	$ 100.00	$ 126.46	$ 145.51	$ 148.59	$ 172.37	$ 228.19
Dow Jones U.S. Exploration & Production	$ 100.00	$ 140.56	$ 164.09	$ 157.22	$ 166.37	$ 219.35

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)	**2013**	**2012**	**2011**	**2010**	**2009**
Statement of Operations Data					
Operating revenues	$ 1,746,278	$ 1,204,546	$ 979,864	$ 863,104	$ 893,085
Impairment of oil and gas properties and other assets				40,903	17,622
Gain / (loss) on sale of assets[1]	21,351	50,635	63,382	106,294	(3,303)
Income from operations	550,480	306,133	306,850	266,439	282,269
Net income	279,773	131,730	122,408	103,386	148,343
Basic earnings per share[2]	$ 0.67	$ 0.31	$ 0.29	$ 0.25	$ 0.36
Diluted earnings per share[2]	$ 0.66	$ 0.31	$ 0.29	$ 0.25	$ 0.36
Dividends per common share[2]	$ 0.06	$ 0.04	$ 0.03	$ 0.03	$ 0.03

	December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
Balance Sheet Data					
Properties and equipment, net	$ 4,546,227	$ 4,310,977	$ 3,934,584	$ 3,762,760	$ 3,358,199
Total assets	4,981,080	4,616,313	4,331,493	4,005,031	3,683,401
Current portion of long-term debt		75,000			
Long-term debt	1,147,000	1,012,000	950,000	975,000	805,000
Stockholders' equity	2,204,602	2,131,447	2,104,768	1,872,700	1,812,514

(1) *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 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 a net aggregate 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.*

(2) *All Earnings per share and Dividends per common share figures have been retroactively adjusted for the 2-for-1 split of our common stock effective August 6, 2013.*

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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 2013 increased by 55% from 2012. We produced 413.6 Bcfe, or 1.1 Bcfe per day, in 2013, compared to 267.7 Bcfe, or 731.4 Mmcfe per day, in 2012. Natural gas production increased by 141.0 Bcf, or 56%, to 394.2 Bcf in 2013 compared to 253.2 Bcf in 2012. This increase was primarily the result of higher production in the Marcellus Shale associated with our drilling program and continued expansion of infrastructure in the area. Partially offsetting the production increase in the Marcellus Shale were decreases in production primarily in Texas, Oklahoma and West Virginia due to reduced natural gas drilling and normal production declines. Crude oil/condensate/NGL production increased by 814 Mbbls, or 34%, from 2,407 Mbbls in 2012 to 3,221 Mbbls in 2013. This increase was the result of higher production resulting from our oil-focused drilling program in south Texas and, to a lesser extent, Oklahoma.

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 2013 was $3.56 per Mcf, 3% lower than the $3.67 per Mcf price realized in 2012. Our average realized crude oil price for 2013 was $101.13 per Bbl, less than 1% lower than the $101.65 per Bbl price realized in 2012. 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.

We drilled 181 gross wells (153.5 net) with a success rate of 98% in 2013 compared to 170 gross wells (117.8 net) with a success rate of 98% in 2012. Our 2013 total capital and exploration spending was $1.2 billion compared to $978.5 million in 2012. The increase in capital spending was the result of our Marcellus Shale horizontal drilling program in northeast Pennsylvania and our drilling program in the Eagle Ford Shale and Pearsall Shale in south Texas. In both 2013 and 2012, we allocated our planned program for capital and exploration expenditures among our various operating areas based on return expectations, availability of services and human resources. We plan to continue such method of allocation in 2014. Our 2014 drilling program includes between $1.3 billion and $1.4 billion in capital and exploration expenditures. Funding of the program is expected to be provided by operating cash flow, existing cash and, if required, borrowings under our 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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FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2013 were from funds generated from the sale of natural gas and crude oil production (including hedge realizations from our commodity derivatives), proceeds from the sales of certain oil and gas properties during the year and net borrowings under our credit facility. These cash flows were primarily used to fund our capital and exploration expenditures, repayments of debt 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 characterized by peak 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 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 credit facility and liquidity available to meet our working capital requirements.

	Year Ended December 31,		
(In thousands)	**2013**	**2012**	**2011**
Cash flows provided by operating activities	$ 1,024,526	$ 652,093	$ 501,839
Cash flows used in investing activities	(918,207)	(765,514)	(487,620)
Cash flows provided by / (used in) financing activities	(113,655)	114,246	(40,257)
Net increase / (decrease) in cash and cash equivalents	$ (7,336)	$ 825	$ (26,038)

Operating Activities. 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.

Net cash provided by operating activities in 2012 increased by $150.3 million over 2011. 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 and higher realized crude oil prices partially offset by lower realized natural gas prices. Equivalent production volumes increased by 43% for 2012 compared to 2011 as a result of higher natural gas and crude oil production. Average realized natural gas prices decreased by 18% for 2012 compared to 2011, while average realized crude oil prices increased by 12% compared to the same period.

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 $152.7 million from 2012 to 2013 due to a $266.8 million increase in capital and exploration expenditures and a $12.0 million

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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. The $277.9 million increase from 2011 to 2012 was due to a decrease of $234.3 million of proceeds from the sale of assets, an increase of $36.7 million in capital and exploration expenditures and an increase of $6.9 million associated with our equity investment in Constitution.

Financing Activities. 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 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. Cash flows provided by financing activities increased by $154.5 million from 2011 to 2012 due to $162.0 million of higher net borrowings, partially offset by an increase in dividends paid of $4.2 million and cash paid for capitalized debt issuance costs of $4.0 million.

In December 2013, we exercised the $500 million accordion feature of our amended credit facility, thereby increasing the available credit line to $1.4 billion. As of December 31, 2013, the borrowing base under our amended credit facility was $2.3 billion. See Note 5 of the Notes to the Consolidated Financial Statements for further details.

At December 31, 2013, we had $460.0 million of borrowings outstanding under our credit facility at a weighted-average interest rate of 2.0% compared to $325.0 million of borrowings outstanding at a weighted-average interest rate of 2.2% at December 31, 2012. As of December 31, 2013, we had $939.0 million available for future borrowings under our 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, 2013.

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our 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 credit facility, we have the capacity to finance our spending plans and maintain our strong financial position.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(Dollars in thousands)	**2013**	**2012**
Debt[(1)]	$ 1,147,000	$ 1,087,000
Stockholders' equity	2,204,602	2,131,447
Total capitalization	$ 3,351,602	$ 3,218,447
Debt to capitalization	34%	34%
Cash and cash equivalents	$ 23,400	$ 30,736

(1) *Includes $460.0 million and $325.0 million of borrowings outstanding under our revolving credit facility at December 31, 2013 and 2012, respectively, and $75.0 million of current portion of long-term debt at December 31, 2012.*

For the year ended December 31, 2013, we paid dividends of $25.2 million ($0.06 per share) on our common stock. In July 2013, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.01 per share to $0.02 per share. A regular dividend has been declared for each quarter since we became a public company in 1990.

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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 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:

	Year Ended December 31,		
(In thousands)	**2013**	**2012**	**2011**
Capital Expenditures			
Drilling and facilities	$ 1,096,705	$ 843,528	$ 780,673
Leasehold acquisitions	71,234	88,880	71,134
Pipeline and gathering	1,222	94	7,378
Other	8,816	8,547	9,840
	1,177,977	941,049	869,025
Exploration expense	18,165	37,476	36,447
Total	$ 1,196,142	$ 978,525	$ 905,472

We plan to drill approximately 155 to 175 gross wells (or 150 to 170 net) in 2014 compared to 181 gross wells (153.5 net) drilled in 2013. In 2014, we plan to spend between approximately $1.3 billion and $1.4 billion in total capital and exploration expenditures (excluding expected contributions of approximately $36.4 million to Constitution), compared to $1.2 billion in 2013. 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.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2013 are set forth in the following table:

		Payments Due by Year			
(In thousands)	**Total**	**2014**	**2015 to 2016**	**2017 to 2018**	**2019 & Beyond**
Long-term debt	$ 1,147,000	$	$ 20,000	$ 772,000	$ 355,000
Interest on long-term debt(1)	346,835	54,830	109,659	97,323	85,023
Transportation and gathering agreements(2)	1,812,785	96,939	262,497	240,973	1,212,376
Drilling rig commitments(2)	28,032	16,344	11,688		
Operating leases(2)	14,341	5,881	7,469	991	
Equity investment contribution commitments(3)	142,990	36,422	106,568		
Total contractual obligations	$ 3,491,983	$ 210,416	$ 517,881	$ 1,111,287	$ 1,652,399

(1) *Interest payments have been calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2013. Interest payments on our credit facility were calculated by assuming that the December 31, 2013 outstanding balance of $460.0 million will be outstanding through the May 2017 maturity date. A constant interest rate of 2.0% was assumed, which was the December 31, 2013 weighted-average interest rate. Actual results will differ from these estimates and assumptions.*

(2) *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.*

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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, 2013 was $75.9 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 oil and 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.

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 $0.06 per Mcfe and an increase of $0.07 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 $0.07 per Mcfe and an increase of $0.08 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.

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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 crude 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 $7.3 million or decrease by approximately $4.9 million, respectively, per year.

As these properties are developed and reserves are proven, 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 Obligation

The majority of our asset retirement obligation (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 over the asset's useful life, while increases in the discounted ARO liability resulting from the passage of time (accretion expense) are reflected as depreciation, depletion and amortization expense.

Accounting for Derivative Instruments and Hedging Activities

Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each quarterly period, these instruments are marked-to-market. The gain or loss on the change in fair value is recorded as accumulated other comprehensive income, a component of equity, to the extent that the derivative instrument is designated as a hedge and is effective. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges and the change in fair value of derivatives not qualifying as hedges are recorded currently in earnings as a component of natural gas and crude oil and condensate revenue 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 based 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 binomial or Black-Scholes valuation model depending on 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.

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Recent Accounting Pronouncements

Effective January 1, 2013, we adopted the amended disclosure requirements prescribed in ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities" and ASU No. 2013-01, "Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities." This guidance impacted the disclosures associated with our commodity derivatives and did not impact our consolidated financial position, results of operations or cash flows.

Effective January 1, 2013, we adopted the amended disclosure requirements prescribed in ASU No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." This guidance impacted our disclosures associated with items reclassified from accumulated other comprehensive income / (loss) and did not impact our consolidated financial position, results of operations or cash flows.

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 operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0 and 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. Our revolving credit agreement also requires us to maintain a current ratio of 1.0 to 1.0. At December 31, 2013, 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 and also the areas in which we operate.

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, changes in natural gas prices may have a more significant impact on our financial results.

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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 derivative financial instruments. Most recently, we have used financial instruments 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

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 due to an increase in natural gas and crude oil and condensate revenues, partially offset by higher operating costs.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

Revenue Variances (In thousands)	Year Ended December 31, 2013	2012	Variance Amount	Percent
Natural gas[1]	$ 1,405,262	$ 934,134	$ 471,128	50%
Crude oil and condensate	291,418	227,933	63,485	28%
Brokered natural gas	36,450	34,005	2,445	7%
Other	13,148	8,968	4,180	47%

(1) *Natural gas revenues exclude the unrealized loss of $0.5 million from the change in fair value of our derivatives not designated as hedges in 2012. There were no unrealized gains or losses in 2013.*

	Year Ended December 31, 2013	2012	Variance Amount	Percent	Increase (Decrease) (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 derivative instrument 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 derivative instrument settlements, which increased the price by $1.48 per Bbl in 2013 and $5.00 per Bbl in 2012.*

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Natural Gas Revenues

The increase in natural gas revenues of $471.1 million, excluding the impact of the unrealized losses discussed above, is due to higher production, partially offset by lower realized natural gas prices. The increase in our production was the result of our Marcellus Shale drilling program 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 drilling program in south Texas and, to a lesser extent, Oklahoma, partially offset by lower realized crude oil prices.

Brokered Natural Gas

	Year Ended December 31, 2013	Year Ended December 31, 2012	Variance Amount	Variance Percent	Price and Volume Variances (In thousands)
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.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the increase / (decrease) to operating revenues from the realized impact of cash settlements for derivative instruments designated as cash flow hedges and the net unrealized change in fair value of other financial derivative instruments:

(In thousands)	Year Ended December 31, 2013	Year Ended December 31, 2012

Cash Flow Hedges		
Natural gas	$ 52,733	$ 225,108
Crude oil	4,269	11,218
Other Derivative Financial Instruments		
Natural gas basis swaps		(494)
	$ 57,002	$ 235,832

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Operating and Other Expenses

(In thousands)	Year Ended December 31, 2013	2012	Variance 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%
(Gain) / loss on sale of assets	$ (21,351)	$ (50,635)	$ (29,284)	(58%)
Interest expense and other	64,942	68,293	(3,351)	(5%)
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, 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 by $1.4 million from 2012 to 2013. See the preceding table titled "*Brokered Natural Gas Revenue and Cost*" for further analysis.

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 by $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 $1.44 per Mcfe for 2013 compared to $1.61 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 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 and Other, Net. Interest expense and other decreased by $3.4 million as a result lower debt extinguishment costs of $1.3 million associated with our credit facility amendment in May 2012 and lower interest expense as a result of the repayment of $75 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 credit facility due to an increase in weighted-average borrowings under our revolving credit facility 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 on our revolving credit facility borrowings of approximately 2.3% during 2013 compared to approximately 3.0% during 2012.

Income Tax Expense. Income tax expense increased by $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 in establishing deferred income taxes.

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2012 and 2011 Compared

We reported net income for 2012 of $131.7 million, or $0.31 per share, compared to net income for 2011 of $122.4 million, or $0.29 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 costs.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

Revenue Variances (In thousands)	Year Ended December 31, 2012	2011	Variance Amount	Percent
Natural gas(1)	$ 934,134	$ 797,482	$ 136,652	17%
Crude oil and condensate	227,933	125,972	101,961	81%
Brokered natural gas	34,005	51,190	(17,185)	(34%)
Other	8,968	6,185	2,783	45%

(1)

Natural gas revenues exclude the unrealized loss of $0.5 million and $1.0 million from the change in fair value of our derivatives not designated as hedges in 2012 and 2011, respectively.

	Year Ended December 31, 2012	2011	Variance Amount	Percent	Increase (Decrease) (In thousands)
Price Variances					
Natural gas(1)	$ 3.67	$ 4.46	$ (0.79)	(18%)	$ (195,172)
Crude oil and condensate(2)	$ 101.65	$ 90.49	$ 11.16	12%	25,034
Total					$ (170,138)
Volume Variances					
Natural gas (Bcf)	253.2	178.8	74.4	42%	$ 331,824
Crude oil and condensate (Mbbl)	2,242	1,392	850	61%	76,927
Total					$ 408,751

(1)

These prices include the realized impact of derivative instrument settlements, which increased the price by $0.89 per Mcf in 2012 and $0.47 per Mcf in 2011.

(2)

These prices include the realized impact of derivative instrument settlements, which increased the price by $5.00 per Bbl in 2012 and $1.01 per Bbl in 2011.

Natural Gas Revenues

The increase in natural gas revenues of $136.7 million, excluding the impact of the unrealized losses discussed above, is due to higher production, partially offset by lower realized natural gas prices. The increase in our production was the result of higher production in the Marcellus Shale associated with our drilling program and expanded infrastructure, partially offset by the sale of certain oil and gas properties in the Rockies in the fourth quarter of 2011 and lower production in Texas, Oklahoma and West Virginia due to a shift from natural gas to oil-focused drilling and normal production declines.

Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $102.0 million is primarily due to higher production associated with our Eagle Ford Shale drilling program in south Texas and the Marmaton oil play in Oklahoma and higher realized oil prices.

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Brokered Natural Gas

	Year Ended December 31, 2012	Year Ended December 31, 2011	Variance Amount	Variance Percent	Price and Volume Variances (In thousands)
Brokered Natural Gas Sales					
Sales price ($/Mcf)	$ 3.57	$ 4.97	$ (1.40)	(28%)	$ (13,328)
Volume brokered (Mmcf)	x 9,527	x 10,303	(776)	(8%)	(3,857)
Brokered natural gas (In thousands)	$ 34,005	$ 51,190			$ (17,185)
Brokered Natural Gas Purchases					
Purchase price ($/Mcf)	$ 2.99	$ 4.25	$ (1.26)	(30%)	$ 12,034
Volume brokered (Mmcf)	x 9,527	x 10,303	(776)	(8%)	3,298
Brokered natural gas (In thousands)	$ 28,502	$ 43,834			$ 15,332
Brokered natural gas margin (In thousands)	$ 5,503	$ 7,356			$ (1,853)

The $1.9 million decrease in brokered natural gas margin is a result of a decrease in brokered volumes and a decrease in sales price that outpaced the decrease in purchase price.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the increase / (decrease) to operating revenues from the realized impact of cash settlements for derivative instruments designated as cash flow hedges and the net unrealized change in fair value of other financial derivative instruments:

(In thousands)	Year Ended December 31, 2012	Year Ended December 31, 2011
Cash Flow Hedges		
Natural gas	$ 225,108	$ 84,937
Crude oil	11,218	1,403
Other Derivative Financial Instruments		
Natural gas basis swaps	(494)	(965)
	$ 235,832	$ 85,375

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Operating and Other Expenses

(In thousands)	Year Ended December 31, 2012	2011	Variance Amount	Percent
Operating and Other Expenses				
Direct operations	$ 118,243	$ 107,409	$ 10,834	10%
Transportation and gathering	143,309	73,322	69,987	95%
Brokered natural gas	28,502	43,834	(15,332)	(35%)
Taxes other than income	48,874	27,576	21,298	77%
Exploration	37,476	36,447	1,029	3%
Depreciation, depletion and amortization	451,405	343,141	108,264	32%
General and administrative	121,239	104,667	16,572	16%
Total operating expense	$ 949,048	$ 736,396	$ 212,652	29%
(Gain) / loss on sale of assets	$ (50,635)	$ (63,382)	$ (12,747)	(20%)
Interest expense and other	68,293	71,663	(3,370)	(5%)
Income tax expense	106,110	112,779	(6,669)	(6%)

Total costs and expenses from operations increased by $212.7 million from 2011 to 2012. The primary reasons for this fluctuation are as follows:

Direct operations increased $10.8 million largely due to increased operating costs primarily driven by increased production. Contributing to the increase were higher employee related expenses and lease maintenance costs, partially offset by lower workover costs.

Transportation and gathering increased $70.0 million due to higher throughput as a result of higher production and transportation rates and the commencement of various transportation and gathering arrangements in late 2011 and throughout 2012, primarily in northeast Pennsylvania and south Texas.

Brokered natural gas decreased $15.3 million from 2011 to 2012. See the preceding table titled "*Brokered Natural Gas Revenue and Cost*" for further analysis.

Taxes other than income increased $21.3 million due to additional costs associated with the passage of an "impact fee" in Pennsylvania on Marcellus Shale production that was imposed by state legislature in February 2012 and higher production tax expense due to fewer production tax refunds and credits received in 2012 compared to 2011.

Exploration increased $1.0 million as the result of increased exploration activity, partially offset by lower geophysical and geological costs due to fewer acquisitions and purchases of seismic data.

Depreciation, depletion and amortization increased $108.3 million, which includes a $131.4 million increase due to higher equivalent production volumes, partially offset by an $8.5 million decrease due to a lower DD&A rate of $1.61 per Mcfe for 2012 compared to $1.64 Mcfe for 2011. The increase in DD&A was offset by a decrease in amortization of unproved properties of $14.4 million as a result of a decrease in amortization rates due to the success of our drilling programs in Pennsylvania and south Texas and the sale of certain Pearsall Shale undeveloped leaseholds in south Texas in the second quarter of 2012.

General and administrative increased by $16.6 million due to higher pension expense of $14.0 million associated with the termination of our qualified pension plan and the related settlement that occurred in the second quarter 2012, and higher legal costs and professional fees of $6.0 million. Also contributing to the increase was the accrual of $1.9 million associated with

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fines and penalties assessed by the Office of Natural Resources Revenue for certain alleged volume reporting matters (which we are currently disputing) related to properties we no longer own and a $2.2 million charitable contribution to fund the construction of a hospital in northeast Pennsylvania. These increases were partially offset by $6.3 million of lower stock-based compensation expense primarily associated with the mark-to-market of our liability-based performance awards due to changes in our stock price in 2012 compared to 2011.

Gain / (Loss) on Sale of Assets. 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. During the 2011, an aggregate net gain of $63.4 million was recognized primarily due to the sale of certain undeveloped leaseholds in east Texas and the sale of other non-core assets.

Interest Expense, Net. Interest expense and other decreased by $3.4 million due to a decrease in the weighted-average effective interest rate on the credit facility, which decreased to approximately 3.0% during 2012 compared to approximately 4.1% during 2011, partially offset by a decrease in weighted- average borrowings under our credit facility based on weighted-average debt of $283.8 million in 2012 compared to weighted-average debt of $317.7 million in 2011.

Income Tax Expense. Income tax expense decreased by $6.7 million due a lower effective tax rate partially offset by increased pretax income. The effective tax rates for 2012 and 2011 were 44.6% and 48.0%, respectively. The effective tax rate was lower due to a decrease in the impact of our state rates used in establishing deferred income taxes.

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 market prices for North American natural gas production. Commodity prices can be volatile and unpredictable.

Derivative Instruments and Hedging Activities

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. 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 hedging arrangements.

Periodically, we enter into commodity derivative instruments, including collar and swap agreements, to hedge our exposure to price fluctuations on natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity hedges 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.

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As of December 31, 2013, we had the following outstanding commodity derivatives designated as hedging instruments:

			Collars				Swaps	
			Floor		Ceiling			Estimated Fair Value Asset (Liability) (In thousands)
Type of Contract	Volume	Contract Period	Range	Weighted-Average	Range	Weighted-Average	Weighted-Average	
Natural gas	336.8 Bcf	Jan. 2014 - Dec. 2014	$3.60 - $4.37	$ 4.13	$4.22 - $4.80	$ 4.51		$ (4,018)
Natural gas	35.5 Bcf	Jan. 2014 - Dec. 2014					$ 4.12	(6,983)
								$ (11,001)

In the above table, natural gas prices are stated per Mcf. The amounts set forth under the estimated fair value asset (liability) column in the table above represent our total unrealized derivative position at December 31, 2013 and exclude the impact of non-performance risk. Non-performance risk 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 2013, natural gas collars with floor prices ranging from $3.09 to $5.15 per Mcf and ceiling prices ranging from $3.98 to $6.23 per Mcf covered 241.7 Bcf, or 61%, of our natural gas production at an average price of $3.96 per Mcf. Crude oil swaps covered 1,095 Mbbl, or 38% of our crude oil production at an average price $101.90 per Bbl.

We are exposed to market risk on our 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. We do not anticipate any material impact on our financial results due to non-performance by third parties. Our primary derivative contract counterparties are Bank of America, Bank of Montreal, Goldman Sachs, ING Capital Markets, JPMorgan and Morgan Stanley.

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 long-term debt is the estimated amount we would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes and 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 credit facility is based on interest rates currently available to us.

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

	December 31, 2013		December 31, 2012	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 1,147,000	$ 1,224,273	$ 1,087,000	$ 1,213,474
Current maturities			(75,000)	(77,175)
Long-term debt, excluding current maturities	$ 1,147,000	$ 1,224,273	$ 1,012,000	$ 1,136,299

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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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in *Internal Control Integrated Framework (1992)* 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 appearing 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 28, 2014

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CABOT OIL & GAS CORPORATION

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 23,400	$ 30,736
Restricted cash	28,094	
Accounts receivable, net	222,476	172,419
Inventories	17,468	14,173
Deferred income taxes	81,855	
Derivative instruments	3,019	50,824
Other current assets	2,587	2,158
Total current assets	378,899	270,310
Properties and equipment, net (Successful efforts method)	4,546,227	4,310,977
Other assets	55,954	35,026
	$ 4,981,080	$ 4,616,313
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 288,801	$ 312,480
Current portion of long-term debt		75,000
Accrued liabilities	73,601	49,597
Derivative instruments	13,912	192
Income taxes payable	31,591	1,667
Deferred income taxes		5,203
Total current liabilities	407,905	444,139
Postretirement benefits	33,554	38,864
Long-term debt	1,147,000	1,012,000
Deferred income taxes	1,067,912	882,672
Asset retirement obligation	73,853	67,016
Other liabilities	46,254	40,175
Total liabilities	2,776,478	2,484,866
Commitments and contingencies		
Stockholders' equity		
Common stock:		
Authorized 480,000,000 shares of $0.10 par value in 2013 and 2012, respectively		
Issued 422,014,681 shares and 420,859,462 shares in 2013 and 2012, respectively	42,201	42,086

Additional paid-in capital	710,940	695,566
Retained earnings	1,627,805	1,373,264
Accumulated other comprehensive income / (loss)	(8,361)	23,880
Less treasury stock, at cost:		
5,618,166 and 808,800 shares in 2013 and 2012, respectively	(167,983)	(3,349)
Total stockholders' equity	2,204,602	2,131,447
	$ 4,981,080	$ 4,616,313

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

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CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF OPERATIONS

(In thousands, except per share amounts)	Year Ended December 31, 2013	2012	2011
OPERATING REVENUES			
Natural gas	$ 1,405,262	$ 933,640	$ 796,517
Crude oil and condensate	291,418	227,933	125,972
Brokered natural gas	36,450	34,005	51,190
Other	13,148	8,968	6,185
	1,746,278	1,204,546	979,864
OPERATING EXPENSES			
Direct operations	140,856	118,243	107,409
Transportation and gathering	229,489	143,309	73,322
Brokered natural gas cost	29,936	28,502	43,834
Taxes other than income	43,045	48,874	27,576
Exploration	18,165	37,476	36,447
Depreciation, depletion and amortization	651,052	451,405	343,141
General and administrative	104,606	121,239	104,667
	1,217,149	949,048	736,396
Gain / (loss) on sale of assets	21,351	50,635	63,382
INCOME FROM OPERATIONS	550,480	306,133	306,850
Interest expense and other	64,942	68,293	71,663
Income before income taxes	485,538	237,840	235,187
Income tax expense	205,765	106,110	112,779
NET INCOME	$ 279,773	$ 131,730	$ 122,408
Earnings per share			
Basic	$ 0.67	$ 0.31	$ 0.29
Diluted	$ 0.66	$ 0.31	$ 0.29
Weighted-average common shares outstanding			
Basic	420,188	419,075	416,996
Diluted	422,375	421,987	421,522
Dividends per common share	$ 0.06	$ 0.04	$ 0.03

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)	**2013**	**2012**	**2011**
Net income	$ 279,773	$ 131,730	$ 122,408
Other comprehensive income / (loss), net of taxes:			
Reclassification adjustment for settled hedge contracts(1)	(34,548)	(144,456)	(52,840)
Changes in fair value of hedge contracts(2)	(2,720)	53,815	163,704
Pension and postretirement benefits:			
Net gain / (loss)(3)	4,641	1,258	(13,814)
Settlement(4)			3,380
Amortization of net obligation at transition(5)			387
Amortization of prior service cost(6)		134	640
Amortization of net loss(7)	386	8,582	6,718
Foreign currency translation adjustment(8)			55
Total other comprehensive income / (loss)	(32,241)	(80,667)	108,230
Comprehensive income / (loss)	$ 247,532	$ 51,063	$ 230,638

(1) *Net of income taxes of $22,454, $91,870 and $33,500 for the year ended December 31, 2013, 2012 and 2011, respectively.*

(2) *Net of income taxes of $1,803, $(34,890) and $(103,963) for the year ended December 31, 2013, 2012 and 2011, respectively.*

(3) *Net of income taxes of $(2,977), $(815) and $9,085 for the year ended December 31, 2013, 2012 and 2011, respectively.*

(4) *Net of income taxes of $0, $0 and $(2,143) for the year ended December 31, 2013, 2012 and 2011, respectively.*

(5) *Net of income taxes of $0, $0 and $(245) for the year ended December 31, 2013, 2012 and 2011, respectively.*

(6) *Net of income taxes of $0, $(87) and $(406) for the year ended December 31, 2013, 2012 and 2011, respectively.*

(7) *Net of income taxes of $(255), $(5,324) and $(4,257) for the year ended December 31, 2013, 2012 and 2011, respectively.*

(8) *Net of income taxes of $0, $0 and $(34) for the year ended December 31, 2013, 2012 and 2011, 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, 2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 279,773	$ 131,730	$ 122,408
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	651,052	451,405	343,141
Deferred income tax expense	138,380	80,929	74,744
(Gain) / loss on sale of assets	(21,351)	(50,635)	(63,382)
Exploration expense	808	14,000	13,977
Unrealized (gain) / loss on derivative instruments		494	965
Amortization of debt issuance costs	3,693	5,265	4,381
Stock-based compensation, pension and other	45,863	46,872	52,940
Changes in assets and liabilities:			
Accounts receivable, net	(49,398)	(58,037)	(19,893)
Income taxes	29,002	3,055	(27,345)
Inventories	(3,033)	7,104	7,708
Other current assets	(428)	(1,198)	1,143
Accounts payable and accrued liabilities	(22,908)	18,843	8,546
Other assets and liabilities	(8,014)	2,266	(17,494)
Stock-based compensation tax benefit	(18,913)		
Net cash provided by operating activities	1,024,526	652,093	501,839
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,194,739)	(927,977)	(891,277)
Proceeds from sale of assets	323,501	169,326	403,657
Restricted cash	(28,094)		
Investment in equity method investment	(18,875)	(6,863)	
Net cash used in investing activities	(918,207)	(765,514)	(487,620)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from debt	955,000	400,000	330,000
Repayments of debt	(895,000)	(263,000)	(355,000)
Treasury stock repurchases	(164,634)		
Dividends paid	(25,232)	(16,757)	(12,508)
Stock-based compensation tax benefit	18,913		
Capitalized debt issuance costs	(2,750)	(5,005)	(1,025)
Other	48	(992)	(1,724)
Net cash provided by / (used in) financing activities	(113,655)	114,246	(40,257)
Net increase / (decrease) in cash and cash equivalents	(7,336)	825	(26,038)
Cash and cash equivalents, beginning of period	30,736	29,911	55,949

Cash and cash equivalents, end of period	$	23,400	$	30,736	$	29,911

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	Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income / (Loss)	Retained Earnings	Total
Balance at December 31, 2010	416,840	$ 41,684	808	$ (3,349)	$ 689,657	$ (3,683)	$ 1,148,391	$ 1,872,700
Net income							122,408	122,408
Exercise of stock options and stock appreciation rights	319	32			(1,778)			(1,746)
Stock amortization and vesting	880	88			13,862			13,950
Sale of stock held in rabbi trust					1,734			1,734
Cash dividends at $0.03 per share							(12,508)	(12,508)
Other comprehensive income / (loss)						108,230		108,230
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

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Nature of Operations

Cabot Oil & Gas Corporation and its subsidiaries (the Company) are engaged in the development, exploitation, exploration, production and marketing of natural gas, crude 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 crude 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.

On July 23, 2013, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock dividend. The stock dividend was distributed on August 14, 2013 to shareholders of record as of August 6, 2013. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

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 two financial institutions at December 31, 2013 and in one financial institution at December 31, 2012. 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, 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.

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1. Summary of Significant Accounting Policies (Continued)

Equity Method Investment

The Company accounts for its investment 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 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.

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. Accordingly, 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

1. Summary of Significant Accounting Policies (Continued)

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 crude 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 2013, 2012 and 2011, amortization associated with the Company's unproved properties was $53.6 million, $18.1 million and $32.5 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 over the asset's useful life. 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, 2013, there were no assets legally restricted for purposes of settling asset retirement obligations.

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

Derivative and Hedging Activities

The Company enters into derivative contracts, such as swaps or collars, as a hedging strategy to manage commodity price risk associated with its production or other contractual commitments. All hedge transactions are subject to the Company's risk management policy which does not permit speculative trading activities. Gains or losses on these hedging activities are generally recognized over the period that its production or other underlying commitment is hedged as an offset to the specific hedged item. Cash flows related to any recognized gains or losses associated with these hedges are reported as cash flows from operations. If a hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period that the underlying production or other contractual commitment is delivered. Unrealized gains or losses associated with any derivative contract not considered a hedge are recognized currently in the results of operations.

When the designated item associated with a derivative instrument matures or is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on the sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated

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1. Summary of Significant Accounting Policies (Continued)

transaction that is no longer expected to occur or if the hedge is no longer effective, the gain or loss on the derivative is recognized currently in the results of operations to the extent the market value changes in the derivative have not been offset by the effects of the price changes on the hedged item since the inception of the hedge.

Revenue Recognition

Natural gas and crude oil sales result from interests in oil and gas properties owned by the Company. Sales of natural gas and crude 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 other and accrued penalties related to such positions in general and administrative expense in the Consolidated Statement of Operations.

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1. Summary of Significant Accounting Policies (Continued)

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 binomial 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 crude 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, 2013 and 2012, 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. During the year ended December 31, 2011, the Company did not have any one customer account for greater than 10% 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.

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 crude 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 crude 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.

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1. Summary of Significant Accounting Policies (Continued)

Recent Accounting Pronouncements

Effective January 1, 2013, the Company adopted the amended disclosure requirements prescribed in ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities" and ASU No. 2013-01, "Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities." This guidance impacted the disclosures associated with the Company's commodity derivatives (Note 6) and did not impact its consolidated financial position, results of operations or cash flows.

Effective January 1, 2013, the Company adopted the amended disclosure requirements prescribed in ASU No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." This guidance impacted the Company's disclosures associated with items reclassified from accumulated other comprehensive income / (loss) (Note 15) and did not impact its consolidated financial position, results of operations or cash flows.

2. Divestitures

The Company recognized an aggregate net gain on sale of assets of $21.4 million, $50.6 million and $63.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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, subject to post closing adjustments, 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, subject to post closing adjustments, and recognized a $17.5 million loss on sale of assets.

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

In November 2013, the Company deposited $28.3 million of proceeds from the sale of certain oil and gas properties with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. The funds are classified as restricted cash in the Consolidated Balance Sheet and, unless utilized for one or more like-kind exchange transactions, are restricted in their use until April 2014.

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 $251.0 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. As of December 31, 2013, the drilling and completion carry was fully satisfied.

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

In October 2011, the Company sold certain proved oil and gas properties located in Colorado, Utah and Wyoming to BreitBurn Operating L.P., a wholly owned subsidiary of BreitBurn Energy Partners L.P., for $285.0 million and recognized a $4.2 million gain on sale of assets.

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2. Divestitures (Continued)

In May 2011, the Company sold certain of its unproved Haynesville and Bossier Shale oil and gas properties in east Texas to a third party for approximately $47.0 million and recognized a $34.2 million gain on sale of assets.

In February and April 2011, respectively, the Company entered into two participation agreements with third parties related to certain of its Haynesville and Bossier Shale leaseholds in east Texas. Under the terms of the participation agreements, the third parties agreed to fund 100% of the cost to drill and complete certain Haynesville and Bossier Shale wells in the related leaseholds over a multi-year period in exchange for a 75% working interest in the leaseholds. During 2011, the Company received a reimbursement of drilling costs incurred of approximately $12.9 million associated with wells that had commenced drilling prior to the execution of the participation agreements.

In 2011, the Company sold various other unproved properties and other assets for approximately $73.5 million and recognized an aggregate net gain of $25.0 million.

3. Properties and Equipment

Properties and equipment are comprised of the following:

	December 31,	
(In thousands)	**2013**	**2012**
Proved oil and gas properties	$ 6,362,570	$ 5,724,940
Unproved oil and gas properties	375,428	467,483
Gathering and pipeline systems	239,958	239,656
Land, building and other equipment	94,243	86,137
	7,072,199	6,518,216
Accumulated depreciation, depletion and amortization	(2,525,972)	(2,207,239)
	$ 4,546,227	$ 4,310,977

Capitalized Exploratory Well Costs

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

	Year Ended December 31,		
(In thousands)	**2013**	**2012**	**2011**
Balance at beginning of period	$ 10,390	$ 5,328	$ 4,285
Additions to capitalized exploratory well costs pending the determination of proved reserves		10,390	5,328
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(10,198)		(1,138)
Capitalized exploratory well costs charged to expense	(192)	(5,328)	(3,147)
Balance at end of period	$	$ 10,390	$ 5,328

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3. Properties and Equipment (Continued)

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

	December 31,		
(In thousands)	2013	2012	2011
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$	$ 10,390	$ 5,328
Capitalized exploratory well costs that have been capitalized for a period greater than one year			
	$	$ 10,390	$ 5,328

4. Equity Method Investment

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 120 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 is late 2015 through 2016, which was extended from the initial in-service date of early 2015 due to a longer than expected regulatory and permitting process. Accordingly, the Company expects to contribute approximately $143.0 million over the next three years.

During 2013 and 2012, the Company made contributions of $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 $26.9 million and $6.9 million as of December 31, 2013 and 2012, respectively, and is included in other assets in the Consolidated Balance Sheet. There were no material earnings or losses associated with Constitution during 2013 or 2012.

5. Debt and Credit Agreements

The Company's debt consisted of the following:

	December 31,	
(In thousands)	2013	2012
Long-Term Debt		
7.33% weighted-average fixed rate notes	$ 20,000	$ 95,000
6.51% weighted-average fixed rate notes	425,000	425,000
9.78% notes	67,000	67,000
5.58% weighted-average fixed rate notes	175,000	175,000
Credit facility	460,000	325,000
Current Maturities		
7.33% weighted-average fixed rate notes		(75,000)
Long-Term Debt, excluding Current Maturities	$ 1,147,000	$ 1,012,000

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5. Debt and Credit Agreements (Continued)

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

At December 31, 2013, the Company was in compliance with all restrictive financial covenants in both the revolving credit facility and fixed rate notes.

7.33% Weighted-Average Fixed Rate Notes

In July 2001, the Company issued $170 million of 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-year	July 2011	7.26%
Tranche 2	$ 75,000,000	12-year	July 2013	7.36%
Tranche 3	$ 20,000,000	15-year	July 2016	7.46%

Interest on each series of the 7.33% weighted-average fixed rate notes is payable semi-annually. The Company may prepay all or any portion of the Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The Notes contain restrictions on the merger of the Company or any subsidiary with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. Those covenants include a required asset coverage ratio (present value of proved reserves to debt and other liabilities) of at least 1.75 to 1.0 (as amended) and a minimum annual coverage ratio of operating 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.

As of December 31, 2013, the Company has repaid $150 million of aggregate maturities associated with the 7.33% weighted-average fixed rate notes.

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-year	July 2018	6.44%
Tranche 2	$ 100,000,000	12-year	July 2020	6.54%
Tranche 3	$ 80,000,000	15-year	July 2023	6.69%

Interest on each series of the 6.51% weighted-average fixed rate notes is payable semi-annually. The Company may prepay all or any portion of the Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The Notes contain restrictions on the merger of the Company with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. These covenants include a required asset coverage ratio (present value of proved reserves plus adjusted cash (as defined in the note purchase agreement) to debt and other liabilities) of at least 1.75 to 1.0 (as amended) and a minimum annual coverage ratio of operating cash flow to interest

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5. Debt and Credit Agreements (Continued)

expense for the trailing four quarters of 2.8 to 1.0. The Notes are also subject to customary events of default. The Company is required to offer to prepay the Notes upon specified change in control events accompanied by a ratings decline below investment grade.

9.78% Notes

In December 2008, the Company issued $67 million aggregate principal amount of its 10-year 9.78% Series G Senior Notes to a group of four institutional investors in a private placement. Interest on the Notes is payable semi-annually. The Company may prepay all or any portion of the Notes on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The other terms of the Notes are substantially similar to the terms of the 6.51% Weighted-Average Fixed Rate Notes.

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-year	January 2021	5.42%
Tranche 2	$ 25,000,000	12-year	January 2023	5.59%
Tranche 3	$ 62,000,000	15-year	January 2026	5.80%

Interest on each series of the 5.58% weighted-average fixed rate notes is payable semi-annually. The Company may prepay all or any portion of the Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The other terms of the Notes are substantially similar to the terms of the 6.51% Weighted-Average Fixed Rate Notes.

Revolving Credit Agreement

In May 2012, the Company amended its revolving credit facility to adjust the margins associated with borrowings under the facility and extended the maturity date from September 2015 to May 2017. The credit facility, as amended, provides for an available credit line of $900 million with an accordion feature, which allows the Company to increase the available credit line by an additional $500 million if one or more of the existing or new banks agree to provide such increased amount. In December 2013, the Company exercised the $500 million accordion feature on the amended credit facility thereby increasing the available credit line to $1.4 billion. The other terms and conditions of the amended facility are generally consistent with the terms and conditions of the credit facility prior to its amendment.

In December 2013, the Company incurred $2.8 million of debt issuance costs associated with its exercise of the accordion feature under the amended credit facility, which were capitalized and will be amortized over the remaining term of the amended credit facility, along with the residual unamortized costs of $10.6 million. The amortization of debt issuance costs is included in interest expense and other in the Consolidated Statement of Operations.

The amended credit facility 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

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5. Debt and Credit Agreements (Continued)

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 the outstanding level of borrowings 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.

The Borrowing Base is redetermined annually under the terms of the 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. As of December 31, 2013, the Company's borrowing base was $2.3 billion.

Interest rates under the amended credit facility are based on Euro-Dollars (LIBOR) or Base Rate (Prime) indications, plus a margin. The associated margins increase if the total indebtedness under the 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 amended credit facility provides for a commitment fee on the unused available balance at annual rates ranging from 0.375% to 0.50%.

The amended credit facility also contains various customary restrictions, which include the following (with all calculations based on definitions contained in the agreement):

(a) Maintenance of a minimum annual coverage ratio of operating 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 working capital to debt of 1.75 to 1.0.

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

(d) Prohibition on the merger or sale of all or substantially all of the Company's or any subsidiary's assets to a third party, except under certain limited conditions.

In addition, the amended 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.

The Company's weighted-average effective interest rates for the credit facility during the years ended December 31, 2013, 2012 and 2011 were approximately 2.3%, 3.0% and 4.1%, respectively. As of December 31, 2013 and 2012, the weighted-average interest rate on the Company's credit facility was approximately 2.0% and 2.2%, respectively. Availability under the credit facility at December 31, 2013 was $939.0 million.

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6. Derivative Instruments and Hedging Activities

The Company periodically enters into commodity derivative instruments to hedge 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 hedges 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.

As of December 31, 2013, the Company had the following outstanding commodity derivatives designated as hedging instruments:

			Collars				Swaps
			Floor		Ceiling		
Type of Contract	**Volume**	**Contract Period**	**Range**	**Weighted-Average**	**Range**	**Weighted-Average**	**Weighted-Average**
Natural gas	336.8Bcf	Jan. 2014 - Dec. 2014	$3.60 - $4.37	$ 4.13	$4.22 - $4.80	$ 4.51	
Natural gas	35.5Bcf	Jan. 2014 - Dec. 2014					$ 4.12

In the above table, natural gas prices are stated per Mcf. The change in fair value of derivatives designated as hedges that is effective is recorded in accumulated other comprehensive income in stockholders' equity in the Consolidated Balance Sheet. The ineffective portion of the change in the fair value of derivatives designated as hedges, and the change in fair value of derivatives not designated as hedges, are recorded currently in earnings as a component of natural gas revenue and crude oil and condensate revenue in the Consolidated Statement of Operations.

The following tables reflect the fair value of derivative instruments on the Company's consolidated financial statements:

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**	**2013**	**2012**	**2013**	**2012**
Commodity contracts	Derivative instruments (current assets)	$ 3,019	$ 50,824	$	$
Commodity contracts	Derivative instruments (current liabilites)			13,912	192
		$ 3,019	$ 50,824	$ 13,912	$ 192

At December 31, 2013 and 2012, unrealized losses of $10.9 million ($6.6 million, net of tax) and $50.6 million ($30.7 million, net of tax), respectively, were recorded in accumulated other comprehensive income / (loss) in the Consolidated Balance Sheet. Based upon estimates at December 31, 2013, the Company expects to reclassify $6.6 million in after-tax losses associated with its commodity hedges from accumulated other comprehensive income / (loss) to the Consolidated Statement of Operations over the next 12 months.

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6. Derivative Instruments and Hedging Activities (Continued)

Offsetting of Derivative Assets and Liabilities in the Consolidated Balance Sheet

(In thousands)	Year Ended December 31, 2013	2012
Derivative Assets		
Gross amounts of recognized assets	$ 13,792	$ 54,454
Gross amounts offset in the statement of financial position	(10,773)	(3,630)
Net amounts of assets presented in the statement of financial position	3,019	50,824
Gross amounts of financial instruments not offset in the statement of financial position	373	1,892
Net amount	$ 3,392	$ 52,716
Derivative Liabilities		
Gross amounts of recognized liabilities	$ 24,685	$ 3,822
Gross amounts offset in the statement of financial position	(10,773)	(3,630)
Net amounts of liabilities presented in the statement of financial position	13,912	192
Gross amounts of financial instruments not offset in the statement of financial position		
Net amount	$ 13,912	$ 192

Effect of Derivative Instruments on the Consolidated Statement of Operations

Derivatives Designated as Hedging Instruments

	Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		
	Year Ended December 31,		
(In thousands)	2013	2012	2011
Commodity contracts	$ (4,523)	$ 88,705	$ 267,667

Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		
	Year Ended December 31,		
(In thousands)	2013	2012	2011
Natural gas revenues	$ 52,733	$ 225,108	$ 84,937
Crude oil and condensate revenues	4,269	11,218	1,403

	$	57,002	$	236,326	$	86,340

For the years ended December 31, 2013, 2012 and 2011, respectively, there was no ineffectiveness recorded in the Company's Consolidated Statement of Operations related to its derivative instruments designated as hedges.

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6. Derivative Instruments and Hedging Activities (Continued)

Derivatives Not Designated as Hedging Instruments

(In thousands)	Location of Gain (Loss) Recognized in Income on Derivative	Year Ended December 31, 2013	2012	2011
Commodity contracts	Natural gas revenues	$	$ (494)	$ (965)

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 obligation under the agreement. The Company enters into derivative contracts with multiple counterparties in order to limit its exposure to individual counterparties. The Company also has netting arrangements with all of its counterparties that allow it to offset assets and liabilities from separate derivative contracts with that counterparty.

Certain counterparties to the Company's derivative instruments are also lenders under its credit facility. The Company's credit facility and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of its derivative liabilities in certain situations.

7. Fair Value Measurements

The Company follows the authoritative accounting guidance for measuring fair values 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 valuation should be chosen.

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments of oil and gas properties and other assets, at fair value on a nonrecurring basis. As none of the Company's other non-financial assets and liabilities were impaired as of December 31, 2013, 2012 and

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7. Fair Value Measurements (Continued)

2011 and no other fair value measurements were required to be recognized on a non-recurring basis, 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 obligation 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, 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

(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, 2012
Assets				
Deferred compensation plan	$ 10,608	$	$	$ 10,608
Derivative contracts		9,473	44,981	54,454
Total assets	$ 10,608	$ 9,473	$ 44,981	$ 65,062

Liabilities				
Deferred compensation plan	$ 23,893	$	$	$ 23,893
Derivative contracts			3,822	3,822
Total liabilities	$ 23,893	$	$ 3,822	$ 27,715

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, 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

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7. Fair Value Measurements (Continued)

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 volatility factors. An increase (decrease) in this unobservable input 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)	**2013**	**2012**	**2011**
Balance at beginning of period	$ 41,159	$ 195,127	$ 14,746
Total gains or (losses) (realized or unrealized):			
Included in earnings[1]	52,733	224,614	85,375
Included in other comprehensive income	(37,249)	(157,478)	181,346
Settlements	(52,733)	(221,489)	(86,340)
Transfers in and/or out of level 3		385	
Balance at end of period	$ 3,910	$ 41,159	$ 195,127

(1) *A loss of $0.5 million and $1.0 million for the years ended December 31, 2012 and 2011, respectively, was unrealized and included in natural gas revenues in the Consolidated Statement of Operations.*

There were no transfers between Level 1 and Level 2 fair value measurements for the years ended December 31, 2013, 2012 and 2011.

Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying 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 1in the fair value hierarchy and the remaining financial instruments are classified as Level 2.

The fair value of long-term 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 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 credit facility is based on interest rates currently available to the Company. The Company's long-term debt is valued

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7. Fair Value Measurements (Continued)

using an income approach and classified as Level 3 in the fair value hierarchy due to the unobservable nature of the inputs.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of long-term debt are as follows:

	December 31, 2013		December 31, 2012	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 1,147,000	$ 1,224,273	$ 1,087,000	$ 1,213,474
Current maturities			(75,000)	(77,175)
Long-term debt, excluding current maturities	$ 1,147,000	$ 1,224,273	$ 1,012,000	$ 1,136,299

8. Asset Retirement Obligation

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

(In thousands)	**Year Ended December 31, 2013**
Balance at beginning of period	$ 67,016
Liabilities incurred	5,295
Liabilities settled	(762)
Liabilities divested	(6,400)
Accretion expense	3,691
Change in estimate	7,013
Balance at end of period	$ 75,853

The change in estimate during 2013 is attributable to increased costs for services and related materials to plug and abandon wells in certain areas of our operations. As of December 31, 2013, approximately $2.0 million, which represents the current portion of the Company's asset retirement obligation, is included in accrued liabilities in the Consolidated Balance Sheet.

9. Commitments and Contingencies

Transportation and Gathering Agreements

The Company has entered into certain natural gas, crude 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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9. Commitments and Contingencies (Continued)

As of December 31, 2013, the Company's future minimum obligations under transportation and gathering agreements are as follows:

(In thousands)		
2014	$	96,939
2015		125,350
2016		137,147
2017		132,070
2018		108,903
Thereafter		1,212,376
	$	1,812,785

Drilling Rig Commitments

As of December 31, 2013, the Company entered into certain drilling rig commitments for two drilling rigs for its capital program in the Marcellus Shale with initial terms ranging from two to three years. As of December 31, 2013, the future minimum commitments under these agreements are $16.3 million in 2014, $7.2 million in 2015 and $4.4 million in 2016.

Lease Commitments

The Company leases certain office space, warehouse facilities, vehicles, and machinery and equipment under cancelable and non-cancelable leases. Rent expense under these arrangements totaled $12.3 million, $11.6 million and $13.6 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2013 are as follows:

(In thousands)		
2014	$	5,881
2015		4,985
2016		2,484
2017		825
2018		166
Thereafter		
	$	14,341

Legal Matters

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

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9. Commitments and Contingencies (Continued)

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.

Environmental Matters

Pennsylvania Department of Environmental Protection

On December 15, 2010, the Company entered into a consent order and settlement agreement (CO&SA) with the Pennsylvania Department of Environmental Protection (PaDEP), addressing a number of environmental issues originally identified in 2008 and 2009, including alleged releases of drilling mud and other substances, alleged record keeping violations at various wells and alleged natural gas contamination of water supplies to 14 households in Susquehanna County, Pennsylvania. During 2010 and 2011, the Company paid a total of $1.3 million in settlement of fines and penalties sought or claimed by the PaDEP related to this matter. On January 11, 2011, certain of the affected households appealed the CO&SA to the Pennsylvania Environmental Hearing Board (PEHB). On October 17, 2011, the Company requested PaDEP approval to resume hydraulic fracturing and new natural gas well drilling operations in the affected area, along with a request to cease temporary water deliveries to the affected households pursuant to prior consent orders with the PaDEP. The PaDEP concurred that temporary water deliveries to the property owners are no longer necessary. On November 18, 2011, certain of the affected households appealed this order to the PEHB, which appeal was later consolidated with the CO&SA appeal. All appellants have accepted their portion of the $2.2 million that was placed into escrow in 2011 for their benefit and on October 18, 2012 dismissed their appeal to the PEHB. Subsequent to the withdrawal of the appeals, the PEHB allowed three groups of appellants to reinstate their appeal. The appeal is set for trial in April 2014.

The Company is in continuing discussions with the PaDEP to address the results of the Company's natural gas well test data, water quality sampling and water well headspace screenings, which were required pursuant to the CO&SA. On August 21, 2012, the PaDEP notified the Company that it could commence completion operations on existing wells within the concerned area.

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10. Income Taxes

Income tax expense is summarized as follows:

(In thousands)	Year Ended December 31, 2013	2012	2011
Current			
Federal	$ 56,544	$ 24,618	$ 39,749
State	10,841	563	(1,714)
Total	67,385	25,181	38,035
Deferred			
Federal	111,147	57,704	46,599
State	27,233	23,225	28,145
Total	138,380	80,929	74,744
Total income tax expense	$ 205,765	$ 106,110	$ 112,779

Total income taxes were different than the amounts computed by applying the statutory federal income tax rate as follows:

(In thousands)	Year Ended December 31, 2013	2012	2011
Statutory federal income tax rate	35%	35%	35%
Computed "expected" federal income tax	$ 169,938	$ 83,244	$ 82,316
State income tax, net of federal income tax benefit	17,513	9,609	8,989
Deferred tax adjustment related to change in overall state tax rate	15,220	13,596	19,068
Other, net	3,094	(339)	2,406
Total income tax expense	$ 205,765	$ 106,110	$ 112,779

The tax effects of temporary differences that resulted in significant portions of the deferred tax liabilities and deferred tax assets were as follows:

(In thousands)	December 31, 2013	2012
Deferred Tax Assets		
Net operating loss carryforward	$ 78,182	$ 137,422
Alternative minimum tax carryforward	182,212	125,862
Foreign tax credit	4,822	4,923
Derivatives and hedging	3,946	
Incentive compensation	36,450	30,985

Deferred compensation	11,988	8,485
Post-retirement benefits	13,965	16,498
Other	3,619	7,078
Total	335,184	331,253
Deferred Tax Liabilities		
Properties and equipment	1,321,241	1,199,213
Derivatives and hedging		19,915
Total	1,321,241	1,219,128
Net deferred tax liabilities	$ 986,057	$ 887,875

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10. Income Taxes (Continued)

As of December 31, 2013, the Company had alternative minimum tax credit carryforwards of $182.2 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 $221.1 million and $378.6 million for federal and state reporting purposes, respectively, the majority of which will expire between 2019 and 2033. 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, 2013 are approximately $66.4 million.

Unrecognized Tax Positions

A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

	Year Ended December 31,		
(In thousands)	**2013**	**2012**	**2011**
Unrecognized tax benefit balance at beginning of year	$	$	$
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			
Settlements			
Unrecognized tax benefit balance at end of year	$ 3,700	$	$

During 2013, the Company recorded unrecognized tax benefits of $3.7 million based on the allocation of certain income tax gains associated with its recent divestitures for purposes of computing state income taxes. If recognized, the net tax benefit of $2.4 million would not have a material effect on the Company's effective tax rate.

The Company files income tax returns in the U.S. federal jurisdiction, various states and other jurisdictions. The Company is no longer subject to examinations by state authorities before 2009 or by federal authorities before 2010. The Company is not currently under examination by the Internal Revenue Service.

11. Employee Benefit Plans

Pension Plan

Prior to its termination in 2010, the Company had a 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 an 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).

On July 28, 2010, the Company notified its employees of its plan to terminate its qualified pension plan, with the plan and its related trust to be liquidated effective September 30, 2010. The Company then amended and restated the qualified pension plan to freeze benefit accruals, to provide for termination of the plan, to allow for an early retirement enhancement to be available to all active participants as of September 30, 2010 regardless of their age and years of service as of that date, and to make certain changes that were required or made desirable as a result of developments in the law.

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11. Employee Benefit Plans (Continued)

Because no further benefits would accrue under the qualified pension plan after September 30, 2010, the Company's related non-qualified pension plan was effectively frozen and no additional benefits were accrued under those arrangements after September 30, 2010. 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.

During 2012, the Company contributed $11.3 million to its qualified pension plan to fund the liquidation of the trust under the qualified pension plan. During 2011, the Company contributed $14.3 million to its qualified and non-qualified pension plans? including $7.3 million to fund the final distribution of benefits under non-qualified pension plan and $7.0 million contribution to the qualified pension plan. As of December 31, 2013 and 2012, there were no benefit obligations or plan assets associated with the qualified and non-qualified pension plans recorded in the Company's Consolidated Balance Sheet. During 2012 and 2011, benefit payments of $51.0 million and $10.8 million and annuity payments of $7.0 million and $18.1 million, respectively, were made from the qualified and non-qualified pension plans. Substantially all of these payments were made as part of the liquidation of these plans.

The components of net periodic benefit costs, included in general and administrative expense in the Consolidated Statement of Operations, were as follows:

	Year Ended December 31,		
(In thousands)	**2013**	**2012**	**2011**
Qualified and Non-Qualified Pension Plan[(1)(2)]			
Interest cost	$	$ 922	$ 2,826
Expected return on plan assets		(1,747)	(4,103)
Settlement		7,007	5,523
Amortization of prior service cost		221	1,046
Amortization of net loss		13,082	10,527
Net periodic pension cost	$	$ 19,485	$ 15,819

(1) *On July 13, 2012, the Company made a final distribution of benefits from the qualified pension plan.*

(2) *On December 15, 2011, the Company made a final distribution of benefits from the non-qualified pension plan.*

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 270 retirees and their dependents and 265 retirees and their dependents at the end of 2013 and 2012, respectively.

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

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11. Employee Benefit Plans (Continued)

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)	**2013**	**2012**	**2011**
Change in Benefit Obligation			
Benefit obligation at beginning of year	$ 40,168	$ 39,969	$ 31,947
Service cost	1,739	1,513	1,403
Interest cost	1,500	1,537	1,717
Actuarial (gain) / loss	(7,618)	(2,073)	6,015
Benefits paid	(794)	(778)	(1,113)
Benefit obligation at end of year	$ 34,995	$ 40,168	$ 39,969
Change in Plan Assets			
Fair value of plan assets at end of year			
Funded status at end of year	$ (34,995)	$ (40,168)	$ (39,969)

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet consist of the following:

	December 31,		
(In thousands)	**2013**	**2012**	**2011**
Current liabilities	$ 1,441	$ 1,304	$ 1,261
Long-term liabilities	33,554	38,864	38,708
	$ 34,995	$ 40,168	$ 39,969

Amounts Recognized in Accumulated Other Comprehensive Income

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

	December 31,		
(In thousands)	**2013**	**2012**	**2011**
Net actuarial loss	$ 3,010	$ 11,269	$ 14,166
	$ 3,010	$ 11,269	$ 14,166

Under the authoritative accounting guidance, the net actuarial loss is not amortized if it is less than 10% of the postretirement obligation. Accordingly, the Company does not expect to amortize its net actuarial loss from accumulated other comprehensive income during 2014.

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11. Employee Benefit Plans (Continued)

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

(In thousands)	Year Ended December 31, 2013	2012	2011
Components of Net Periodic Postretirement Benefit Cost			
Current year service cost	$ 1,739	$ 1,513	$ 1,403
Interest cost	1,500	1,537	1,717
Amortization of net obligation at transition			632
Amortization of net loss	641	824	448
Net periodic postretirement cost	$ 3,880	$ 3,874	$ 4,200
Other Changes in Benefit Obligations Recognized in Other Comprehensive Income			
Net (gain) / loss	$ (7,618)	$ (2,073)	$ 6,015
Amortization of net obligation at transition			(632)
Amortization of net loss	(641)	(824)	(448)
Total recognized in other comprehensive income	(8,259)	(2,897)	4,935
Total recognized in net periodic benefit cost and other comprehensive income	$ (4,379)	$ 977	$ 9,135

Assumptions

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

	December 31, 2013	2012	2011
Discount rate[1]	4.75%	4.00%	4.25%
Health care cost trend rate for medical benefits assumed for next year	6.50%	7.00%	8.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2018	2015	2015

(1) *Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2013, 2012 and 2011, respectively, the beginning of year discount rates of 4.00%, 4.25% and 5.75% 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. The Company prepaid the life insurance premiums for all retirees retiring before January 1, 2006 eliminating all future premiums for retiree life insurance. A life insurance product is offered to employees allowing employees to continue coverage into retirement by paying the premiums directly to the life insurance provider.

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11. Employee Benefit Plans (Continued)

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	$ 627	$ (500)
Effect on postretirement benefit obligation	4,956	(4,091)

Cash Flows

Contributions. The Company expects to contribute approximately $1.5 million to the postretirement benefit plan in 2014.

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

(In thousands)	
2014	1,475
2015	1,541
2016	1,652
2017	1,734
2018	1,877
Years 2019 - 2023	12,134

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, 2013, 2012 and 2011, the Company made contributions of $6.9 million, $6.3 million and $5.6 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.

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11. Employee Benefit Plans (Continued)

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. 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 $12.5 million and $10.6 million at December 31, 2013 and 2012, respectively, and is included in other assets in the Consolidated Balance Sheet. Related liabilities, including the Company's common stock, totaled $33.2 million and $23.9 million at December 31, 2013 and 2012, 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.

The Company's common stock held in the rabbi trust is recorded at the market value on the date of deferral, which totaled $5.7 million at December 31, 2013 and 2012, respectively, and is included in additional paid-in capital in stockholders' equity in the Consolidated Balance Sheet. As of December 31, 2013, 534,174 shares of the Company's stock representing vested performance share awards were deferred into the rabbi trust. During 2013, the Company recognized $7.4 million in general and administrative expense in the Consolidated Statement of Operations representing the increase 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 charged to expense plan contributions of $742,605, $661,676 and $522,807 in 2013, 2012 and 2011, respectively, which are included in general and administrative expense in the Consolidated Statement of Operations.

12. Capital Stock

Incentive Plans

Under the Company's 2004 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 2004 Incentive Plan consisting of stock options or stock awards. A total of 20.4 million shares of common stock may be issued under the 2004 Incentive Plan. Under the 2004 Incentive Plan, no more than 7.2 million shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 12.0 million shares may be issued pursuant to incentive stock options. The 2004 Incentive Plan expires on April 29, 2014. At December 31, 2013, 1.7 million shares are available for issuance under the plan.

Common Stock

In May 2012, the stockholders of the Company approved an increase in the authorized number of shares of common stock from 240 million to 480 million shares.

On July 23, 2013, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock dividend. The stock dividend was distributed on August 14, 2013 to shareholders

12. Capital Stock (Continued)

of record as of August 6, 2013. All common stock accounts and per share data were retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

Treasury Stock

The Board of Directors has 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 securities of the Company.

During the year ended December 31, 2013, the Company repurchased 4.8 million shares for a total cost of $164.6 million. In 2012 and 2011, the Company did not repurchase any shares of common stock. Since the authorization date, the Company has repurchased 25.6 million shares of the 40.0 million total shares authorized for a total cost of approximately $249.7 million, of which 20.0 million shares have been retired. No treasury shares have been delivered or sold by the Company subsequent to the repurchase. As of December 31, 2013, 5.6 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 note or credit agreements in place have restricted payment provisions or other provisions limiting dividends.

13. Stock-Based Compensation

Compensation expense for stock-based awards for the years ended December 31, 2013, 2012 and 2011 was $51.8 million, $33.5 million and $39.5 million, respectively.

For the year ended December 31, 2013, the Company realized an $18.9 million tax benefit related to the federal tax deduction in excess of book compensation cost for employee stock-based compensation. The Company is able to recognize this tax benefit only to the extent it reduces the Company's income taxes payable. There were no excess tax benefits recorded for the years ended December 31, 2012 and 2011 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 is based on the average of the high and low 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-vesting basis at each anniversary date over a three or four year service period.

For awards that vest at the end of the service period, expense is recognized ratably using a straight-line approach over the service period. Under the graded-vesting 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.

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13. Stock-Based Compensation (Continued)

The Company used an annual forfeiture rate assumption ranging from 6.0% 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.

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

	Year Ended December 31,					
	2013		2012		2011	
	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	71,508	$ 11.82	476,388	$ 9.18	528,652	$ 8.89
Granted	7,200	35.70	13,100	18.42	39,200	13.83
Vested	(50,902)	10.44	(402,800)	9.03	(29,464)	8.41
Forfeited			(15,180)	8.80	(62,000)	8.80
Outstanding at end of period[1][2]	27,806	$ 20.53	71,508	$ 11.82	476,388	$ 9.18

(1) *As of December 31, 2013, the aggregate intrinsic value was $1.1 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2013 by the number of non-vested restricted stock awards outstanding.*

(2) *As of December 31, 2013, the weighted average remaining contractual term of non-vested restricted stock awards outstanding was 1.0 years.*

Compensation expense recorded for all restricted stock awards for the years ended December 31, 2013, 2012 and 2011 was $0.2 million, $1.1 million and $1.2 million, respectively. Unamortized expense as of December 31, 2013 for all outstanding restricted stock awards was $0.4 million and will be recognized over the next year.

The total fair value of restricted stock awards that vested during 2013, 2012 and 2011 was $1.6 million, $3.6 million and $0.2 million, respectively.

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13. Stock-Based Compensation (Continued)

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. The fair value of these units is based on the average of the high and low stock price on the grant date and compensation expense is recorded immediately. These units immediately vest and 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,					
	2013		2012		2011	
	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	515,468	$ 9.10	687,308	$ 7.88	568,504	$ 7.34
Granted and fully vested	50,853	27.53	76,608	18.28	118,804	10.44
Issued			(248,448)	8.56		
Forfeited						
Outstanding at end of period(1)(2)	566,321	$ 10.75	515,468	$ 9.10	687,308	$ 7.88

(1) *As of December 31, 2013, the aggregate intrinsic value was $22.0 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2013 by the number of outstanding restricted stock units.*

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

Compensation expense recorded for all restricted stock units for the years ended December 31, 2013, 2012 and 2011 was $1.4 million, $1.4 million and $1.2 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.

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13. Stock-Based Compensation (Continued)

The following table is a summary of SAR activity:

	Year Ended December 31,					
	2013		2012		2011	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of period	1,722,444	$ 9.75	2,576,260	$ 8.02	2,942,600	$ 7.64
Granted			240,884	17.59	383,000	10.19
Exercised	(1,054,680)	7.92	(1,094,700)	7.42	(749,340)	7.61
Forfeited or expired						
Outstanding at end of period[1]	667,764	$ 12.63	1,722,444	$ 9.75	2,576,260	$ 8.02
Exercisable at end of period[2]	386,582	$ 11.33	1,145,972	$ 7.97	1,805,328	$ 7.57

(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, 2013, the aggregate intrinsic value and weighted-average remaining contractual term of SARs outstanding was $17.4 million and 4.3 years, respectively.*

(2) *As of December 31, 2013, the aggregate intrinsic value and weighted-average remaining contractual term of SARs exercisable was $10.6 million and 4.1 years, respectively.*

Compensation expense recorded for all outstanding SARs for the years ended December 31, 2013, 2012 and 2011 was $0.3 million, $1.9 million and $2.1 million, respectively. In 2012 and 2011 there was $1.2 million and $0.1 million, respectively, related to the immediate expensing of shares granted to retirement-eligible employees. As of December 31, 2013, unamortized expense for all outstanding SARs was $0.1 million and the weighted average period over which this compensation will be recognized is approximately one year.

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	2011
Weighted-average value per SAR granted during the period	$ 8.16	$ 4.74
Assumptions		
Stock price volatility	55.3%	52.7%
Risk free rate of return	0.9%	2.3%
Expected dividend yield	0.3%	0.3%
Expected term (in years)	5.0	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 continuously compounded equivalent of the U.S. Treasury

(Nominal 10) within the expected term as

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13. Stock-Based Compensation (Continued)

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 7% for purposes of recognizing stock-based compensation expense.

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, 2013, it is considered probable that 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,					
	2013		2012		2011	
	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	1,919,640	$ 12.27	2,627,900	$ 8.12	2,497,040	$ 8.35
Granted	379,540	26.62	567,360	17.59	837,460	10.19
Issued and fully vested	(610,960)	10.13	(1,189,920)	5.66	(575,200)	12.12
Forfeited	(30,240)	17.06	(85,700)	12.11	(131,400)	8.10
Outstanding at end of period	1,657,980	$ 16.25	1,919,640	$ 12.27	2,627,900	$ 8.12

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13. Stock-Based Compensation (Continued)

Hybrid Performance Share Awards. The Hybrid Performance Share Awards shares have a three-year graded performance period. The 2013 awards vest 25% on each of the first and second anniversary dates and 50% on the third anniversary and the 2012 and 2011 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, 2013, it is considered probable that the criteria for these awards will be met.

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

	Year Ended December 31,					
	2013		2012		2011	
	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	592,162	$ 13.11	759,328	$ 9.16	763,576	$ 8.25
Granted	169,980	26.62	234,922	17.59	370,784	10.19
Issued and fully vested	(311,930)	12.03	(402,088)	8.27	(375,032)	8.32
Forfeited						
Outstanding at end of period	450,212	$ 18.96	592,162	$ 13.11	759,328	$ 9.16

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

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13. Stock-Based Compensation (Continued)

fifteen to sixteen other 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,					
	2013		2012		2011	
	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	605,706	$ 10.27	1,495,904	$ 6.07	1,415,168	$ 6.50
Granted	254,980	23.06	234,922	14.16	370,784	7.81
Issued and fully vested			(1,125,120)	5.49	(290,048)	10.38
Forfeited						
Outstanding at end of period	860,686	$ 14.06	605,706	$ 10.27	1,495,904	$ 6.07

(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, 2013 and 2012, was $7.8 million and $7.6 million, respectively. The current portion of the liability, included in accrued liabilities in the Consolidated Balance Sheet at December 31, 2013 was $14.3 million. There was no current liability as of December 31, 2012. The Company made cash payments of $18.4 million, for the year ended December 31, 2012. There was not a cash payout associated with the TSR Performance Share Awards during 2011 and 2013.

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,		
	2013	2012	2011
Fair value per performance share award granted during the period	$ 23.06	$ 14.16	$ 7.81
Assumptions			
Stock price volatility	43.8%	46.7%	62.0%
Risk free rate of return	0.4%	0.4%	1.3%
Expected dividend yield	0.2%	0.2%	0.2%

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13. Stock-Based Compensation (Continued)

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,		
	2013	2012	2011
Fair value per performance share award at the end of the period	$23.96 - $38.61	$19.11 - $24.76	$12.82 - $17.74
Assumptions			
Stock price volatility	30.2% - 35.9%	41.1% - 45.7%	41.9% - 42.7%
Risk free rate of return	0.1% - 0.4%	0.2% - 0.3%	0.1% - 0.3%
Expected dividend yield	0.2%	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, 2013, 2012 and 2011 was $30.9 million, $24.6 million and $28.5 million, respectively. Total unamortized compensation expense related to the equity component of performance shares at December 31, 2013 was $17.0 million and will be recognized over the next two years.

As of December 31, 2013, the aggregate intrinsic value for all performance share awards was $115.1 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2013 by the number of unvested performance share awards outstanding. As of December 31, 2013, the weighted average remaining contractual term of unvested performance share awards outstanding was approximately two years.

On December 31, 2013, the performance period ended for two types of performance share awards that were granted in 2011. 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 2014 and was certified by the Compensation Committee in February 2014. As the Company achieved the three performance metrics, 751,780 shares with a grant date fair value of $7.4 million were issued in February 2014. For the TSR Performance Share Awards, 370,784 shares with a grant date fair value of $2.9 million were issued, in addition to a cash payment of $14.3 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, 2014.

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

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13. Stock-Based Compensation (Continued)

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.

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 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 $11.5 million, $1.4 million and $1.2 million for years ended December 31, 2013, 2012 and 2011. The Company made payments under the Plan of $4.5 million for year ended December 31, 2013. There were no payments made under the Plan for the years ended December 31, 2012 and 2011.

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 $5.1 million, was deferred until 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 $8.3 million, was deferred until 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

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13. Stock-Based Compensation (Continued)

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 IV liability for the respective period:

	December 31, 2013
Valuation Assumptions	
Stock price volatility	38.0%
Risk free rate of return	1.1%
Annual salary increase rate	4.0%
Annual turnover rate	4.6%

Deferred Performance Shares

As of December 31, 2012, 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 2013. During 2013, an increase to the deferred compensation liability of $9.3 million was recognized, representing an increase in the investments held in the rabbi trust from December 31, 2012 to December 31, 2013. The increase 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)	**2013**	**2012**	**2011**
Weighted-average shares basic	420,188	419,075	416,996
Dilution effect of stock appreciation rights and stock awards at end of period	2,187	2,912	4,526
Weighted-average shares diluted	422,375	421,987	421,522
Weighted-average shares excluded from diluted earnings per share due to the anti-dilutive effect	5	85	5

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15. Accumulated Other Comprehensive Income / (Loss)

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

(In thousands)	Net Gains / (Losses) on Cash Flow Hedges	Defined Benefit Pension and Postretirement Benefits	Foreign Currency Translation Adjustment	Total
Balance at December 31, 2010	$ 10,494	$ (14,122)	$ (55)	$ (3,683)
Other comprehensive income before reclassifications	163,704	(13,814)		149,890
Amounts reclassified from accumulated other comprehensive income	(52,840)	11,125	55	(41,660)
Net current-period other comprehensive income	110,864	(2,689)	55	108,230
Balance at December 31, 2011	$ 121,358	$ (16,811)	$	$ 104,547
Other comprehensive income before reclassifications	53,815	1,258		55,073
Amounts reclassified from accumulated other comprehensive income	(144,456)	8,716		(135,740)
Net current-period other comprehensive income	(90,641)	9,974		(80,667)
Balance at December 31, 2012	$ 30,717	$ (6,837)	$	$ 23,880
Other comprehensive income before reclassifications	(2,720)	4,641		1,921
Amounts reclassified from accumulated other comprehensive income	(34,548)	386		(34,162)
Net current-period other comprehensive income	(37,268)	5,027		(32,241)
Balance at December 31, 2013	$ (6,551)	$ (1,810)	$	$ (8,361)

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

(In thousands)	Year Ended December 31, 2013	2012	2011	Affected Line Item in the Condensed Consolidated Statement of Operations
Net Gains / (Losses) on Cash Flow Hedges				
Commodity contracts	$ 52,733	$ 225,108	$ 84,937	Natural gas revenues
Commodity contracts	4,269	11,218	1,403	Crude oil and condensate revenues
Defined Benefit Pension and Postretirement Benefits				
Settlement			(5,523)	General and administrative expense
Amortization of net obligation at transition			(632)	General and administrative expense
Amortization of prior service cost		(221)	(1,046)	General and administrative expense
Amortization of net loss	(641)	(13,906)	(10,975)	General and administrative expense
Foreign currency translation adjustment			(89)	
	56,361	222,199	68,075	Total before tax
	(22,199)	(86,459)	(26,415)	Tax (expense) / benefit
Total reclassifications for the period	$ 34,162	$ 135,740	$ 41,660	Net of tax

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16. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	December 31, 2013	December 31, 2012
Accounts receivable, net		
Trade accounts	$ 215,361	$ 165,070
Joint interest accounts	7,261	5,659
Income taxes receivable	922	
Other accounts	746	2,817
	224,290	173,546
Allowance for doubtful accounts	(1,814)	(1,127)
	$ 222,476	$ 172,419
Inventories		
Natural gas in storage	$ 9,056	$ 7,494
Tubular goods and well equipment	8,396	6,392
Other accounts	16	287
	$ 17,468	$ 14,173
Other current assets		
Prepaid balances and other	2,587	2,158
	$ 2,587	$ 2,158
Other assets		
Deferred compensation plan	$ 12,507	$ 10,608
Debt issuance cost	16,476	17,420
Equity method investment	26,892	6,915
Other accounts	79	83
	$ 55,954	$ 35,026

Accounts payable		
Trade accounts	$ 26,023	$ 14,037
Natural gas purchases	2,052	4,892
Royalty and other owners	79,150	66,321
Accrued capital costs	146,899	164,862
Taxes other than income	13,677	10,224
Drilling advances	14,093	44,203
Producer gas imbalances	69	1,602
Other accounts	6,838	6,339
	$ 288,801	$ 312,480

Accrued liabilities		
Employee benefits	$ 43,599	$ 17,315
Taxes other than income	6,894	8,735
Interest payable	20,211	22,329
Other accounts	2,897	1,218
	$ 73,601	$ 49,597

Other liabilities		
Deferred compensation plan	$ 33,211	$ 23,893
Other accounts	13,043	16,282
	$ 46,254	$ 40,175

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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)	**2013**	**2012**	**2011**
Interest	$ 63,279	$ 64,970	$ 62,353
Income taxes	35,281	22,501	65,352

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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, 2013, 2012 and 2011 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, 2013, 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 2013, 2012 and 2011.

	Natural Gas (Bcf)	Crude Oil & NGLs[1] (Mbbl)	Total (Bcfe)[2]
December 31, 2010	2,644	9,491	2,701
Revision of prior estimates[3]	22	(80)	22
Extensions, discoveries and other additions[4]	629	13,583	710
Production	(179)	(1,444)	(188)
Sales of reserves in place[5]	(206)	(1,080)	(212)
December 31, 2011	2,910	20,470	3,033
Revision of prior estimates[6]	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[7]	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[8]	(103)	(4,879)	(132)
December 31, 2013	5,295	26,538	5,454
Proved Developed Reserves			
December 31, 2010	1,681	7,129	1,724
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
Proved Undeveloped Reserves			
December 31, 2010	963	2,362	977
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

(1) *NGL reserves were less than 1.0% of our total proved equivalent reserves for 2013, 2012 and 2011, and 12.3%, 8.7% and 7.6% of our proved crude oil and NGL reserves for 2013, 2012 and 2011, 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 21.6 Bcfe was primarily due to an upward performance revision of 214.9 Bcfe, primarily in the Dimock field in northeast Pennsylvania, partially offset by (i) a downward revision of 189.8 Bcfe of proved undeveloped reserves that are no longer in the Company's five-year development plan and (ii) a downward revision of 3.6 Bcfe associated with commodity pricing.*

(4) *Extensions, discoveries and other additions were primarily related to drilling activity in the Dimock field located in northeast Pennsylvania. The Company added 1,653.3 Bcfe, 860.6 Bcfe and 616.1 Bcfe of proved reserves in this field in 2013, 2012 and 2011, respectively.*

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(5) *Sales of reserves in place were primarily related to the divestiture of certain oil and gas properties in the Rockies in October 2011 which represented 170.3 Bcfe.*

(6) *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.*

(7) *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.*

(8) *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.*

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to natural gas and crude oil producing activities and the total amount of related accumulated depreciation, depletion and amortization.

	December 31,		
(In thousands)	**2013**	**2012**	**2011**
Aggregate capitalized costs relating to oil and gas producing activities	$ 7,059,200	$ 6,507,137	$ 5,794,724
Aggregate accumulated depreciation, depletion and amortization	2,518,003	2,200,061	1,864,729
Net capitalized costs	$ 4,541,197	$ 4,307,076	$ 3,929,995

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)	**2013**	**2012**	**2011**
Property acquisition costs, unproved	71,234	88,880	71,134
Exploration costs	44,906	59,198	53,484
Development costs	1,069,965	821,806	763,635
Total costs	$ 1,186,105	$ 969,884	$ 888,253

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 be viewed as representative of the current value of the Company.

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

Future costs and selling prices will probably differ from those required to be used in these calculations.

Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations.

Selection of a 10% discount rate is arbitrary and may not be a reasonable measure of the relative risk that is part of realizing future net oil and gas revenues.

Future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows for 2013, 2012 and 2011 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 at December 31, 2013, 2012 and 2011 for natural gas ($ per Mcf) were $3.58, $2.83 and $4.27, for crude oil ($ per Bbl) were $101.17, $102.02 and $94.00, and for NGLs ($ per Bbl) were $28.11, $37.88 and $67.33, respectively. 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)	**2013**	**2012**	**2011**
Future cash inflows	$ 21,383,701	$ 12,826,877	$ 14,303,990
Future production costs	(5,895,024)	(4,300,025)	(3,435,947)
Future development costs	(1,863,534)	(1,614,878)	(1,617,548)
Future income tax expenses	(4,398,348)	(1,873,185)	(2,880,182)
Future net cash flows	9,226,795	5,038,789	6,370,313
10% annual discount for estimated timing of cash flows	(4,527,262)	(2,302,934)	(3,211,587)
Standardized measure of discounted future net cash flows	$ 4,699,533	$ 2,735,855	$ 3,158,726

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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)	**2013**	**2012**	**2011**
Beginning of year	$ 2,735,855	$ 3,158,726	$ 2,734,509
Discoveries and extensions, net of related future costs	2,082,983	911,044	1,026,961
Net changes in prices and production costs	1,320,490	(1,682,131)	219,478
Accretion of discount	313,420	400,091	325,634
Revisions of previous quantity estimates	478,409	139,540	28,443
Timing and other	114,947	(243,688)	(190,427)
Development costs incurred	340,500	282,476	190,295
Sales and transfers, net of production costs	(1,258,094)	(636,633)	(648,261)
Net purchases / (sales) of reserves in place	(275,926)	(37,412)	(207,557)
Net change in income taxes	(1,153,051)	443,842	(320,349)
End of year	$ 4,699,533	$ 2,735,855	$ 3,158,726

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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
2013					
Operating revenues	$ 373,285	$ 449,680	$ 435,850	$ 487,463	$ 1,746,278
Operating income(1)	87,014	164,736	131,532	167,198	550,480
Net income(1)	42,824	89,114	69,889	77,946	279,773
Basic earnings per share(2)	0.10	0.21	0.17	0.19	0.67
Diluted earnings per share(2)	0.10	0.21	0.17	0.19	0.66
2012					
Operating revenues	$ 272,136	$ 265,657	$ 296,874	$ 369,879	$ 1,204,546
Operating income(3)	46,661	78,079	75,775	105,618	306,133
Net income(3)	18,318	35,937	36,608	40,867	131,730
Basic earnings per share(2)	0.05	0.09	0.09	0.10	0.31
Diluted earnings per share(2)	0.05	0.09	0.09	0.10	0.31

(1) *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.*

(2) *All Earnings per share figures have been retroactively adjusted for the 2-for-1 split of the Company's common stock effective August 6, 2013.*

(3) *Operating income and net income include a $67.0 million gain on the disposition of certain of Pearsall shale undeveloped acreage in south Texas in the second quarter, partially offset by an $18.2 million loss on sale of certain of our south Texas proved oil and gas properties in the fourth quarter.*

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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, 2013, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission's rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

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

Management's Report on Internal Control over Financial Reporting

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

Cabot Oil & Gas Corporation's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013. 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 (1992). Based on this assessment management has concluded that, as of December 31, 2013, 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, 2013, 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 2014 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 2014 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 2014 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 2014 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 2014 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 60.

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	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).

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Exhibit Number	Description
*10.1	Form of Change in Control Agreement between the Company and Certain Officers (Form 10-K for 2008).
	(a) Form of Change in Control Agreement between the Company and Certain Officers (Confirmation that Certain Benefits no Longer Apply) (Form 10-K for 2010).
*10.2	Form of Indemnity Agreement between the Company and Certain Officers (Form 10-K for 2012).
*10.3	Deferred Compensation Plan of the Company, as Amended and Restated, Effective January 1, 2011 (Form 10-Q for the quarter ended June 30, 2011).
*10.4	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001 (Form 10-K for 2001).
	(a) Amendment to Employment Agreement between the Company and Dan O. Dinges, effective December 31, 2008 (Form 10-K for 2008).
*10.5	2004 Incentive Plan (Form 10-Q for the quarter ended June 30, 2004).
	(a) First Amendment to the 2004 Incentive Plan effective February 23, 2007 (Form 10-Q for the quarter ended March 31, 2007).
	(b) Second Amendment to the 2004 Incentive Plan Amendment, effective as of December 31, 2008 (Form 10-K for 2008).
*10.6	2012 Form of Non-Employee Director Restricted Stock Unit Award Agreement (Form 10-K for 2012).
*10.7	Forms of Award Agreements for Executive Officers under 2004 Incentive Plan.
	(a) 2012 Form of Restricted Stock Award Agreement (Form 10-K for 2012).
	(b) 2012 Form of Stock Appreciation Rights Award Agreement (Form 10-K for 2012).
	(c) 2012 Form of Performance Share Award Agreement (Officers) (Form 10-K for 2012).
	(d) 2012 Form of Hybrid Performance Share Award Agreement (Form 10-K for 2012).
	(e) 2012 Form of Performance Share Award Agreement (Employees) (Form 10-K for 2012).
10.8	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).
*10.9	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).
*10.10	Nonemployee Director Deferred Compensation Plan effective December 21, 2012 (Form 10-K for 2012).

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Exhibit Number	Description
10.11	Amended and Restated Credit Agreement, dated as of September 22, 2010, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, Bank of Montreal, as Documentation Agent, and the Lenders party thereto (Form 10-Q for the quarter ended September 30, 2010).
10.12	First Amendment to Amended and Restated Credit Agreement, dated as of May 4, 2012, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities as Syndication Agent, Bank of Montreal as Documentation Agent, and the Lenders party thereto (Form 10-Q for the quarter ended June 30, 2012).
10.13	Second Amendment to Amended and Restated Credit Agreement, dated as of July 18, 2012, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities and Bank of Montreal as Co-Syndication Agents, BNP Paribas and Wells Fargo as Co-Documentation Agents, and the Lenders party thereto (Form 10-Q for the quarter ended September 30, 2012).
10.14	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.
21.1	Subsidiaries of Cabot Oil & Gas Corporation.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Miller and Lents, Ltd.
31.1	302 Certification Chairman, President and Chief Executive Officer.
31.2	302 Certification Vice President and Chief Financial Officer.
32.1	906 Certification.
99.1	Miller and Lents, Ltd. Audit Letter.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Compensatory plan, contract or arrangement.

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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 28th of February 2014.

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 Dan O. Dinges	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 28, 2014
/s/ SCOTT C. SCHROEDER Scott C. Schroeder	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 28, 2014
/s/ TODD M. ROEMER Todd M. Roemer	Controller (Principal Accounting Officer)	February 28, 2014
/s/ RHYS J. BEST Rhys J. Best	Director	February 28, 2014
/s/ JAMES R. GIBBS James R. Gibbs	Director	February 28, 2014
/s/ ROBERT L. KEISER Robert L. Keiser	Director	February 28, 2014
/s/ ROBERT KELLEY Robert Kelley	Director	February 28, 2014
/s/ P. DEXTER PEACOCK P. Dexter Peacock	Director	February 28, 2014
/s/ W. MATT RALLS W. Matt Ralls	Director	February 28, 2014