EQT Corp
Form 10-K
February 20, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM ___________ TO __________

COMMISSION FILE NUMBER 1-3551

EQT CORPORATION

(Exact name of registrant as specified in its charter)

PENNSYLVANIA	**25-0464690**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

625 Liberty Avenue	**15222**
Pittsburgh, Pennsylvania	(Zip Code)
(Address of principal executive offices)	

Registrant s telephone number, including area code: (412) 553-5700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes _X_ No ___

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 ___ No _X_

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes _X_ No ___

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

Yes _X_ No ___

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

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 _X_
Non-accelerated filer ___

Accelerated filer ___
Smaller reporting company ___

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

Yes ___ No _X

The aggregate market value of voting stock held by non-affiliates of the registrant

as of June 30, 2013: $11.9 billion

The number of shares (in thousands) of common stock outstanding

as of January 31, 2014: 150,893

DOCUMENTS INCORPORATED BY REFERENCE

The Company s definitive proxy statement relating to the annual meeting of shareholders (to be held April 30, 2014) will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2013 and is incorporated by reference in Part III to the extent described therein.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

Commonly Used Terms

AFUDC Allowance for Funds Used During Construction carrying costs for the construction of certain long-term assets are capitalized and amortized over the related assets estimated useful lives. The capitalized amount for construction of regulated assets includes interest cost and a designated cost of equity for financing the construction of these regulated assets.

Appalachian Basin the area of the United States composed of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie in the Appalachian Mountains.

basis when referring to commodity pricing, the difference between the futures price for a commodity and the corresponding sales price at various regional sales points. The differential commonly is related to factors such as product quality, location, transportation capacity availability and contract pricing.

British thermal unit a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

collar a financial arrangement that effectively establishes a price range for the underlying commodity. The producer bears the risk and benefit of fluctuation between the minimum (floor) price and the maximum (ceiling) price.

continuous accumulations natural gas and oil resources that are pervasive throughout large areas, have ill-defined boundaries and typically lack or are unaffected by hydrocarbon-water contacts near the base of the accumulation.

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.

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, a service well or a stratigraphic test well.

feet of pay footage penetrated by the drill bit into the target formation.

futures contract an exchange-traded contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price.

gas all references to gas in this report refer to natural gas.

gross gross natural gas and oil wells or gross acres equal the total number of wells or acres in which the Company has a working interest.

hedging the use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

horizontal drilling drilling that ultimately is horizontal or near horizontal to increase the length of the well bore penetrating the target formation.

margin call a demand for additional margin deposits when forward prices move adversely to a derivative holder s position.

margin deposits funds or good faith deposits posted during the trading life of a derivative contract to guarantee fulfillment of contract obligations.

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NGL natural gas liquids those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing plants. Natural gas liquids include primarily propane, butane and iso-butane.

net net natural gas and oil wells or net acres are determined by summing the fractional ownership working interests the Company has in gross wells or acres.

net revenue interest the interest retained by the Company in the revenues from a well or property after giving effect to all third-party interests (equal to 100% minus all royalties on a well or property).

play a proven geological formation that contains commercial amounts of hydrocarbons.

proved reserves quantities of oil, natural gas, and NGLs which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

proved developed reserves proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

proved undeveloped reserves (PUDs) proved reserves that can be estimated with reasonable certainty to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.

reservoir a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

royalty interest the land owner s share of oil or gas production, typically 1/8.

throughput the volume of natural gas transported or passing through a pipeline, plant, terminal, or other facility during a particular period.

working gas the volume of natural gas in the storage reservoir that can be extracted during the normal operation of the storage facility.

working interest an interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

Abbreviations

ASC Accounting Standards Codification

CBM Coalbed Methane

CFTC Commodity Futures Trading Commission

EPA U.S. Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

IPO initial public offering

IRS Internal Revenue Service

NYMEX New York Mercantile Exchange

OTC over the counter

SEC Securities and Exchange Commission

Measurements

Bbl = barrel

Btu = one British thermal unit

BBtu = billion British thermal units

Bcf = billion cubic feet

Bcfe = billion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil

being equivalent to 6,000 cubic feet of natural gas

Dth = million British thermal units

Mcf = thousand cubic feet

Mcfe = thousand cubic feet of natural gas

equivalents, with one barrel of NGLs and crude oil

being equivalent to 6,000 cubic feet of natural gas

Mbbl = thousand barrels

MMBtu = million British thermal units

MMcf = million cubic feet

MMcfe = million cubic feet of natural gas

equivalents, with one barrel of NGLs and crude oil

being equivalent to 6,000 cubic feet of natural gas

TBtu = trillion British thermal units

Tcfe = trillion cubic feet of natural gas

equivalents, with one barrel of NGLs and crude oil

being equivalent to 6,000 cubic feet of natural gas

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Cautionary Statements

Disclosures in this Annual Report on Form 10-K contain certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Statements that do not relate strictly to historical or current facts are forward-looking and usually identified by the use of words such as anticipate, estimate, could, would, will, m forecast, approximate, expect, project, intend, plan, believe and other words of similar meaning in connection with any discussion of f operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report on Form 10-K include the matters discussed in the sections captioned Strategy in Item 1, Business and Outlook in Item 7, Management s Discussio and Analysis of Financial Condition and Results of Operations, and the expectations of plans, strategies, objectives and growth and anticipated financial and operational performance of the Company and its subsidiaries, including guidance regarding the Company s strategy to develop its Marcellus and other reserves; drilling plans and programs (including the number, type, feet of pay and location of wells to be drilled, the conversion of drilling rigs to utilize natural gas and the availability of capital to complete these plans and programs); the expiration of leasehold terms before production can be established; production sales volumes (including liquid volumes); gathering and transmission volumes (including the subscription of additional capacity related to the expiration of EQT Midstream Partners, LP firm transportation contracts); infrastructure programs (including the timing, cost and capacity of the transmission and gathering expansion projects); technology (including drilling and completion techniques); monetization transactions, including midstream asset sales (dropdowns) to EQT Midstream Partners, LP and other asset sales, joint ventures or other transactions involving the Company s assets; natural gas prices and changes in basis; reserves; projected capital expenditures; liquidity and financing requirements, including funding sources and availability; hedging strategy; the effects of government regulation and litigation; operation of the Company s fleet vehicles on natural gas; and tax position. The forward-looking statements included in this Annual Report on Form 10-K involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The Company has based these forward-looking statements on current expectations and assumptions about future events. While the Company considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company s control. The risks and uncertainties that may affect the operations, performance and results of the Company s business and forward-looking statements include, but are not limited to, those set forth under Item 1A, Risk Factors, and elsewhere in this Annual Report on Form 10-K.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company does not intend to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise.

In reviewing any agreements incorporated by reference in or filed with this Annual Report on Form 10-K, please remember such agreements are included to provide information regarding the terms of such agreements and are not intended to provide any other factual or disclosure information about the Company. The agreements may contain representations and warranties by the Company, which should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to such agreements should those statements prove to be inaccurate. The representations and warranties were made only as of the date of the relevant agreement or such other date or dates as may be specified in such agreement and are subject to more recent developments. Accordingly, these representations and warranties alone may not describe the actual state of affairs of the Company or its affiliates as of the date they were made or at any other time.

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PART I

Item 1. Business

General

EQT Corporation (EQT or the Company) conducts its business through two business segments: EQT Production and EQT Midstream. EQT Production is one of the largest natural gas producers in the Appalachian Basin with 8.3 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 3.6 million gross acres, including approximately 580,000 gross acres in the Marcellus play, as of December 31, 2013. EQT Midstream provides gathering, transmission and storage services for the Company s produced gas, as well as for independent third parties across the Appalachian Basin.

Key Events in 2013

During 2013, EQT achieved record annual production sales volumes, including a 43% increase in total sales volumes and an 82% increase in Marcellus sales volumes. The Midstream business delivered record gathered volumes that were 39% higher than the previous year. The Company also completed the following transactions that were instrumental in contributing to a successful 2013:

- On July 22, 2013, Sunrise Pipeline, LLC (Sunrise), a subsidiary of the Company, merged with and into Equitrans, L.P. (Equitrans), a subsidiary of EQT Midstream Partners, LP (the Partnership), with Equitrans continuing as the surviving company (the Sunrise Merger). Sunrise continues to be consolidated by the Company as it is still under common control.

- On July 22, 2013, the Partnership completed an underwritten public offering of 12,650,000 common units representing Partnership limited partner interests. Following the offering and the closing of the Sunrise Merger, the Company holds a 44.6% equity interest in the Partnership, including a 2% general partner interest. The Partnership received net proceeds of $529.4 million from the offering, after deducting the underwriters discount and offering expenses of $20.9 million.

- On December 17, 2013, the Company and its wholly-owned subsidiary, Distribution Holdco, LLC (Holdco), completed a previously announced transaction relating to the Company, Holdco, and PNG Companies LLC (PNG Companies), the parent company of Peoples Natural Gas Company LLC. As part of the transaction, the Company and Holdco transferred 100% of their ownership interests in Equitable Gas Company, LLC (Equitable Gas) and Equitable Homeworks, LLC (Homeworks) to PNG Companies. As consideration for this transaction, the Company received a $740.6 million cash payment, based on initial post-closing adjustments, select midstream assets, including an approximately 200-mile FERC-regulated natural gas transmission pipeline that interconnects with the Partnership s transmission and storage system (the AVC facilities), and new commercial arrangements with PNG Companies and its affiliates. These events are collectively referred to in this Annual Report on Form 10-K as the Equitable Gas Transaction.

Equitable Gas and Homeworks comprised substantially all of the Company s previously reported Distribution segment. The financial information of Equitable Gas and Homeworks is reflected as discontinued operations in this Annual Report on Form 10-K with all prior periods recast to reflect the presentation of discontinued operations.

EQT Production Business Segment

EQT believes that it is a technology leader in extended lateral horizontal and completion drilling in the Appalachian Basin and continues to improve its operations through the use of new technology. EQT Production s strategy is to maximize shareholder value by maintaining an industry leading cost structure to profitably develop its reserves. EQT s proved reserves increased 39% in 2013, to a total of 8.3 Tcfe primarily across the Marcellus and Huron shale plays, and also including CBM and other vertical wells. The Company s Marcellus assets, including Upper Devonian assets, contribute approximately 6.2 Tcfe in total proved reserves.

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The following illustration depicts EQT s acreage position within the Marcellus play:

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As of December 31, 2013, the Company s proved reserves were as follows:

(Bcfe)	Marcellus	Huron *	Upper Devonian	CBM/Utica/ Other	Total
Proved Developed	1,899	1,118	109	860	3,986
Proved Undeveloped	4,057	198	106	1	4,362
Total Proved Reserves	5,956	1,316	215	861	8,348

* Includes the Lower Huron, Cleveland, Berea sandstone and other Devonian age formations.

The Company s natural gas wells are generally low-risk, having a long reserve life with relatively low development and production costs on a per unit basis. Assuming that future annual production from these reserves is consistent with 2013, the remaining reserve life of the Company s total proved reserves, as calculated by dividing total proved reserves by 2013 produced volumes, is 23 years.

The Company invested approximately $1,237 million on well development during 2013, with total production sales volumes hitting a record high of 378.2 Bcfe, an increase of 43% over the previous year. Capital spending for EQT Production is expected to be approximately $1.9 billion in 2014 (excluding land acquisitions), the majority of which will be used to support the drilling of approximately 357 gross wells, including 186 Marcellus wells, 120 Huron wells, 30 Upper Devonian wells and 21 wells in the Utica Shale of Ohio. During the past three years, the Company s number of wells drilled (spud) and related capital expenditures for well development were:

	Years Ended December 31,		
Gross wells spud:	**2013**	**2012**	**2011**
Horizontal Marcellus*	168	127	105
Horizontal Huron	50	7	115
Horizontal Utica	7	1	
Total horizontal	225	135	220
Other			2
Total	225	135	222

Capital expenditures for well development: (in millions):			
Horizontal Marcellus*	$ 1,103	$ 810	$ 686
Horizontal Huron	79	22	226
Horizontal Utica	46	4	
Total horizontal	1,228	836	912
Other	9	21	26
Total	$ 1,237	$ 857	$ 938

* Includes Upper Devonian formations

EQT Midstream Business Segment

The Appalachian Basin has been an area of significant natural gas production growth in recent years. The Company believes that the current footprint of its midstream assets, which spans a wide area of the Marcellus Shale in southwestern Pennsylvania and northern West Virginia, is a competitive advantage that uniquely positions it for growth. In conjunction with the continued growth of EQT Production and other producers in the Marcellus, EQT Midstream is strategically positioned to capitalize on the rapidly increasing need for gathering and

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transmission infrastructure in the region. In particular, there is a need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia.

In 2012, the Company formed the Partnership to own, operate, acquire and develop midstream assets in the Appalachian Basin. The Partnership provides midstream services to the Company and other third parties through its two primary assets: the Partnership s transmission and storage system and the Partnership s gathering system. As of December 31, 2013, the Company held a 42.6% limited partner interest and a 2% general partner interest in the Partnership, whose results are consolidated in the Company s financial statements. Unless otherwise noted, discussions of EQT Midstream s business, operations and results in this Annual Report on Form 10-K include the Partnership s business, operations and results. The Company records the noncontrolling interest of the public limited partners in its financial statements.

The Company s gathering system includes approximately 9,450 miles of gathering lines, 1,600 miles of which are FERC-regulated, low-pressure gathering lines owned by the Partnership. The left-hand map on page 11 depicts the Company s gathering lines and compressor stations in relationship to the Marcellus Shale formation. During 2013, the Company completed various gathering line expansion projects that added approximately 385 MMcf per day of incremental gathering capacity and resulted in year-end Marcellus gathering capacity of 1,500 MMcf per day, 1,150 MMcf per day in Pennsylvania and 350 MMcf per day in West Virginia. To support the ongoing production of natural gas throughout the Marcellus region, the Company plans to add approximately 440 MMcf per day of incremental gathering capacity in 2014, 120 MMcf per day in Pennsylvania and 320 MMcf per day in West Virginia.

EQT Midstream s transmission and storage system includes approximately 900 miles of FERC-regulated interstate pipeline that connects to seven interstate pipelines and multiple distribution companies. The interstate pipeline system includes approximately 700 miles of pipe owned by Equitrans and referred to as the Equitrans transmission and storage system. Equitrans is owned by the Partnership. EQT Midstream s transmission and storage system also includes an approximately 200 mile pipeline referred to as the Allegheny Valley Connector (AVC), which was acquired by the Company in connection with the Equitable Gas Transaction.

The transmission and storage system is supported by eighteen natural gas storage reservoirs with approximately 660 MMcf per day of peak delivery capability and 47 Bcf of working gas capacity. Fourteen of these reservoirs, representing 400 MMcf per day of peak delivery capability and 32 Bcf of working gas capacity, are owned by the Partnership. The storage reservoirs are clustered in two geographic areas connected to the Partnership s transmission and storage system, with ten in southwestern Pennsylvania and eight in northern West Virginia. The AVC facilities include four storage reservoirs owned by the Company and are operated by the Partnership under a lease between the Partnership and an affiliate of the Company.

The right-hand map on page 11 depicts the Company s transmission lines, storage pools and compressor stations in relationship to the Marcellus Shale formation. The Company completed a number of midstream expansion projects in 2013 to take advantage of rapid production development in the Marcellus play. During 2013, the Company added approximately 450 MMcf per day of incremental transmission capacity in Pennsylvania through the Morris III interconnect expansion and the Low Pressure East Pipeline uprate projects. As a result of these expansion projects and the AVC acquisition, EQT Midstream year-end total transmission capacity was 2,700 MMcf per day. During 2014, the Company expects to complete the fully subscribed Jefferson compression expansion project, which is expected to add an additional 650 BBtu per day of transmission capacity in Pennsylvania, as well as an expansion of the west-side of its northern West Virginia transmission system, referred to as the West-Side Expansion Project, that is expected to add 100 BBtu per day of capacity.

EQT Midstream also has a gas marketing subsidiary, EQT Energy, LLC (EQT Energy), that provides optimization of capacity and storage assets through its NGL and natural gas sales to commercial and industrial customers within its operational footprint. EQT Energy also provides marketing services and manages approximately 1,000,000 Dth per day of third-party contractual pipeline capacity for the benefit of EQT Production; and has committed to an additional 750,000 Dth per day of contractual capacity to come online in future periods. EQT Energy currently leases 3.2 Bcf of storage-related assets from third parties.

Strategy

EQT s strategy is to maximize shareholder value by maintaining an industry leading cost structure, profitably developing its undeveloped reserves, and effectively and efficiently utilizing its extensive gathering and

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transmission assets that are uniquely positioned across the Marcellus Shale and in close proximity to the northeastern United States markets.

EQT believes that it is a technology leader in extended-lateral horizontal drilling and completion in the Appalachian Basin and continues to improve its operations through the use of new technology. Substantially all of the Company s acreage is held by production or in fee; therefore, EQT Production is able to develop its acreage in the most economical manner through the use of longer laterals and multi-well pads, as opposed to being required to drill less-economical wells in order to retain acreage. The use of multi-well pads, in conjunction with a completion technique known as reduced cluster spacing, has the additional benefit of reducing the overall environmental surface footprint of the Company s drilling operations.

EQT also believes that its midstream assets are strategically located in the Marcellus Shale region spanning a large, prolific area of southwestern Pennsylvania and northern West Virginia providing a competitive advantage that uniquely positions the Company for continued growth. EQT Midstream intends to capitalize on the rapidly growing need for gathering and transmission infrastructure in this region, and in particular the need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia.

The ongoing efforts of the Partnership are also an important support mechanism for EQT s overall business strategy. Through pursuing accretive acquisitions from the Company, capitalizing on economically attractive organic growth opportunities, and attracting additional third-party volumes, the Partnership is expected to provide an ongoing source of capital to the Company.

The Company is also helping to build additional demand for natural gas. In mid-2011, with the assistance of a $700,000 grant received from the Pennsylvania Department of Environmental Protection, EQT opened a public-access natural gas fueling station in Pittsburgh, Pennsylvania. With the growing popularity and importance of this station to numerous fleets throughout the region, the station underwent an expansion in 2013 adding two more service bays. In conjunction with this project, the Company is promoting the use of natural gas fleet vehicles, including its own, and plans to operate 15% of its light-duty vehicle fleet, more than 180 vehicles, on natural gas by the end of 2014. In addition, the Company is operating four drilling rigs that utilize natural gas and one hydraulic fracturing unit, with an additional unit expected in 2014.

See Capital Resources and Liquidity in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K for details regarding the Company s capital expenditures.

Markets and Customers

Natural Gas Sales: The Company s produced natural gas is sold to marketers, utilities and industrial customers located mainly in the Appalachian Basin and a gas processor in Kentucky and West Virginia. Natural gas is a commodity and therefore the Company receives market-based pricing. The market price for natural gas can be volatile as demonstrated by significant declines in late 2011 and early 2012. In addition, the market price for natural gas in the Appalachian Basin experienced a decline relative to the price at Henry Hub, which is the location for pricing NYMEX and natural gas futures, in the second half of 2013 as a result of the increased supply of natural gas in the Northeast region. Changes in the market price for natural gas, including basis, impact the Company s revenues, earnings and liquidity. The Company is unable to predict potential future movements in the market price for natural gas, including Appalachian basis, and thus cannot predict the ultimate impact of prices on its operations; however, the Company monitors the market for natural gas and adjusts strategy and operations as deemed to be appropriate. In order to protect cash flow from undue exposure to the risk of changing commodity prices, the Company hedges a portion of its forecasted natural gas production, most of which is hedged at NYMEX natural gas prices. The Company s hedging strategy and information regarding its derivative instruments is set forth in Commodity Risk Management in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations , Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and in Notes 1 and 5 to the Consolidated Financial Statements.

NGL Sales: The Company sells NGLs from its own production through the EQT Production segment and from gas marketed for third parties by EQT Midstream. Until February 2011, when the Company sold its Langley natural gas processing complex (Langley), the Company processed natural gas in order to extract heavier liquid

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hydrocarbons (propane, iso-butane, normal butane and natural gasoline) from the natural gas stream, primarily from EQT Production s produced gas. NGLs were recovered at Langley and transported to a fractionation plant owned by a third party for separation into commercial components. The third party marketed these components for a fee. The Company also had contractual processing arrangements whereby the Company sold gas to a third-party processor at a weighted average liquids component price. Subsequent to the closing of the sale of Langley to MarkWest Energy Partners, L.P. in February 2011, the processing of the Company s produced natural gas has been performed by a third-party vendor.

The following table presents the effective sales price on an average Mcfe basis to EQT Corporation for sales of produced natural gas, NGLs and oil, with and without hedges, for the years ended December 31:

	2013	2012	2011
Average effective sales price per Mcfe sold (including hedges)	$ 4.13	$ 4.17	$ 5.23
Average effective sales price per Mcfe sold (excluding hedges)	$ 3.77	$ 3.07	$ 4.72

In addition, realized price information for all products is included in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, under the caption Consolidated Operational Data, and incorporated herein by reference.

Natural Gas Gathering: EQT Midstream derives gathering revenues from charges to customers for use of its gathering system in the Appalachian Basin. The gathering system volumes are transported to four major interstate pipelines: Columbia Gas Transmission, East Tennessee Natural Gas Company, Dominion Transmission and Tennessee Gas Pipeline Company. The gathering system also maintains interconnections with the Partnership s transmission and storage system.

Gathering system transportation volumes for 2013 totaled 466.4 BBtu, of which approximately 79% related to gathering for EQT Production, 9% related to third-party volumes and 12% related to volumes for other affiliates of the Company. Revenues from EQT Production and other affiliates accounted for approximately 88% of 2013 gathering revenues.

Natural Gas Transmission, Storage and Marketing: Natural gas transmission and storage operations are executed using transmission and underground storage facilities owned and/or operated by the Company or the Partnership. EQT Energy provides marketing services and third-party contractual pipeline capacity management for the benefit of EQT Production and leases storage capacity in order to take advantage of seasonal spreads where available. EQT Energy also engages in risk management and energy trading activities, the objective of which is to limit the Company s exposure to shifts in market prices and to optimize the use of the Company s assets.

Customers of EQT Midstream s gas transportation, storage, risk management and related services are affiliates and third parties in the northeastern United States, including, but not limited to, Dominion Resources, Inc., Keyspan Corporation, NiSource Inc., PECO Energy Company and UGI Energy Services, Inc.

As of December 31, 2013, the weighted average remaining contract life based on total projected contracted revenues for the Partnership s firm transmission and storage contracts was approximately 15 years. The Company anticipates that the capacity associated with expiring contracts will be remarketed or used by affiliates such that the capacity will remain fully subscribed. In 2013, approximately 80% of transportation volumes and revenues were from affiliates.

The Company had one customer within the EQT Production segment account for approximately 11% of its revenues in 2013. The Company does not believe that the loss of this customer would have a material adverse effect on its business because alternative customers for the Company s natural gas are available. No single customer accounted for more than 10% of revenues in 2012 or 2011.

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Competition

Natural gas producers compete in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and the securing of labor and equipment required to conduct operations. Competitors include independent oil and gas companies, major oil and gas companies and individual producers and operators. Competition for natural gas gathering, transmission and storage volumes is primarily based on rates and other commercial terms, customer commitment levels, timing, performance, reliability, service levels, location, reputation and fuel efficiencies. Key competitors in the natural gas transmission and storage market include companies that own major natural gas pipelines. Key competitors for gathering systems include independent gas gatherers and integrated energy companies. EQT competes with numerous companies when marketing natural gas and NGLs. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users.

Regulation

Regulation of the Company s Operations

EQT Production s exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances. These regulations may affect the costs and timing of developing the Company s natural gas resources.

EQT Production s operations are also subject to conservation and correlative rights regulations, including the regulation of the size of drilling and spacing units or field rule units; the number of wells that may be drilled in a unit or in close proximity to other wells; drilling in the vicinity of coal mining operations and certain other structures; and the unitization or pooling of natural gas properties. Both Kentucky and Virginia allow the statutory pooling or integration of tracts to facilitate development and exploration. In 2013, the Pennsylvania legislature enacted lease integration legislation, which authorizes joint development of existing leases. In West Virginia, it is necessary to rely on voluntary pooling of lands and leases. In addition, state conservation and oil and gas laws generally limit the venting or flaring of natural gas.

EQT Midstream s transmission and gathering operations are subject to various types of federal and state environmental laws and local zoning ordinances, including air permitting requirements for compressor station and dehydration units; erosion and sediment control requirements for compressor station and pipeline construction projects; waste management requirements and spill prevention plans for compressor stations; various recordkeeping and reporting requirements for air permits and waste management practices; compliance with safety regulations; and siting and noise regulations for compressor stations. These regulations may increase the costs of operating existing pipelines and compressor stations and increase the costs of, and the time to develop, new or expanded pipelines and compressor stations.

The interstate natural gas transmission systems and storage operations of EQT Midstream are regulated by the FERC, and certain gathering lines are also subject to rate regulation by the FERC. For instance, the FERC approves tariffs that establish the Partnership s rates, cost recovery mechanisms and other terms and conditions of service to the Partnership s customers. The fees or rates established under the Partnership s tariffs are a function of its costs of providing services to customers, including a reasonable return on invested capital. The FERC s authority over transmission operations also extends to: storage and related services; certification and construction of new interstate transmission and storage facilities; extension or abandonment of interstate transmission and storage services and facilities; maintenance of accounts and records; relationships between pipelines and certain affiliates; terms and conditions of service; depreciation and amortization policies; acquisition and disposition of facilities; the safety of pipelines; and initiation and discontinuation of services.

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In July 2010, the U.S. Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivative market and entities, such as the Company, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), required the CFTC and the SEC to promulgate rules and regulations implementing the new legislation. As of the filing date of this Annual Report, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including the Company, such as recordkeeping and certain reporting obligations. Other CFTC rules that may be relevant to the Company have yet to be proposed or finalized and, in some cases, finalized rules have yet to be implemented. Because significant CFTC rules relevant to natural gas hedging activities are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the new regulations on the Company s hedging program or regulatory compliance obligations. The Company anticipates, however, increased compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

Regulators periodically audit the Company s compliance with applicable regulatory requirements. The Company anticipates that compliance with existing laws and regulations governing current operations will not have a material adverse effect upon its capital expenditures, earnings or competitive position. Additional proposals that affect the oil and gas industry are regularly considered by the U.S. Congress, the states, regulatory agencies and the courts. The Company cannot predict when or whether any such proposals may become effective.

Environmental, Health and Safety Regulation

The business operations of the Company are also subject to various federal, state and local environmental, health and safety laws and regulations pertaining to, among other things, the release, emission or discharge of materials into the environment; the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes); the safety of employees and the general public; pollution; site remediation; and preservation or protection of human health and safety, natural resources, wildlife and the environment. The Company must take into account environmental, health and safety regulations in, among other things, planning, designing, constructing (including drilling), operating and abandoning wells, pipelines and related facilities.

The Company has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material to the Company s financial position, results of operations or liquidity.

Vast quantities of natural gas deposits exist in shale and other formations. It is customary in the Company s industry to recover natural gas from these shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into a shale gas formation. These deeper formations are geologically separated and isolated from fresh ground water supplies by overlying rock layers. The Company s well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers. To assess water sources near our drilling locations, the Company conducts baseline and, as appropriate, post-drilling water testing at all water wells within at least 2,500 feet of our drilling pads. Legislative and regulatory efforts at the federal level and in some states have sought to render more stringent permitting and compliance requirements for hydraulic fracturing. If passed into law, the additional permitting requirements for hydraulic fracturing may increase the cost to or limit the Company s ability to obtain permits to construct wells.

Climate Change

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. Effective January 1, 2011, the EPA began regulating greenhouse gas emissions by subjecting new facilities and major modifications to existing facilities that emit large amounts of greenhouse gases to the permitting requirements of the federal Clean Air Act. In addition, the U.S. Congress has been considering bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company s cost of environmental

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compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. Climate change and greenhouse gas legislation or regulation could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Conversely, legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because the combustion of natural gas results in substantially fewer carbon emissions per Btu of heat generated than other fossil fuels, such as coal. The effect on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

Employees

The Company and its subsidiaries had 1,621 employees at the end of 2013, and none are subject to a collective bargaining agreement.

Availability of Reports

The Company makes certain filings with the SEC, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through its website, http://www.eqt.com, as soon as reasonably practicable after the date they are filed with, or furnished to, the SEC. The filings are also available at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. These filings are also available on the internet at http://www.sec.gov.

Composition of Segment Operating Revenues

Presented below are operating revenues as a percentage of total operating revenues for each class of products and services representing greater than 10% of total operating revenues.

	For the Years Ended December 31,		
	2013	**2012**	**2011**
EQT Production:			
Natural gas sales	61%	55%	51%
EQT Midstream:			
Gathering revenue	18%	20%	17%
Natural gas liquids sales (a)	6%	8%	10%

(a) NGL sales are included in the operations of both EQT Production and EQT Midstream.

Financial Information about Segments

See Note 4 to the Consolidated Financial Statements for financial information by business segment including, but not limited to, revenues from external customers, operating income and total assets.

Jurisdiction and Year of Formation

The Company is a Pennsylvania corporation formed in 2008 in connection with a holding company reorganization of the former Equitable Resources, Inc.

Financial Information about Geographic Areas

Substantially all of the Company s assets and operations are located in the continental United States.

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Environmental

See Note 18 to the Consolidated Financial Statements for information regarding environmental matters.

Item 1A. Risk Factors

Risks Relating to Our Business

In addition to the other information contained in this Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. Please note that additional risks not presently known to us or that are currently considered immaterial may also have a negative impact on our business and operations. If any of the events or circumstances described below actually occur, our business, financial condition or results of operations could suffer and the trading price of our common stock could decline.

Natural gas price volatility may have an adverse effect upon our revenue, profitability, future rate of growth and liquidity.

Our revenue, profitability, future rate of growth and liquidity depend upon the price for natural gas. The markets for natural gas are volatile and fluctuations in prices will affect our financial results. Natural gas prices are affected by a number of factors beyond our control, which include: weather conditions; the supply of and demand for natural gas; regional basis differentials; national and worldwide economic and political conditions; the price and availability of alternative fuels; the availability, proximity and capacity of pipelines, other transportation facilities, and gathering, processing and storage facilities; and government regulations, such as regulation of natural gas transportation and price controls.

Lower natural gas prices may result in decreases in the revenue, operating income and cash flow for each of our businesses, a reduction in drilling activity and the construction of new transportation capacity and downward adjustments to the value of oil and gas properties which may cause us to incur non-cash charges to earnings. Moreover, if we fail to control our operating costs during periods of lower natural gas prices, we could further reduce our operating income. A reduction in operating income or cash flow will reduce our funds available for capital expenditures and, correspondingly, our opportunities for growth. We are also exposed to the risk of non-performance by our hedge counterparties in the event that changes, positive or negative, in natural gas prices result in derivative contracts with a positive fair value.

Increases in natural gas prices may be accompanied by or result in increased well drilling costs, increased production taxes, increased lease operating expenses, increased volatility in seasonal gas price spreads for our storage assets and increased end-user conservation or conversion to alternative fuels. Significant price increases may subject us to margin calls on our commodity price derivative contracts (hedging arrangements, including futures contracts, swap, collar and option agreements and exchange-traded instruments) which would potentially require us to post significant amounts of cash collateral with our hedge counterparties. The cash collateral, which is interest-bearing, provided to our hedge counterparties, is returned to us in whole or in part upon a reduction in forward market prices, depending on the amount of such reduction, or in whole upon settlement of the related hedged transaction. In addition, to the extent we have hedged our current production at prices below the current market price, we are unable to benefit fully from an increase in the price of natural gas.

We are subject to risks associated with the operation of our wells, pipelines and facilities.

Our business operations are subject to all of the inherent hazards and risks normally incidental to the production, transportation and storage of natural gas and NGLs, such as well site blowouts, cratering and explosions, pipe and other equipment and system failures, uncontrolled flows of natural gas or well fluids, fires, formations with abnormal pressures, pollution and environmental risks and natural disasters. We also face various security risks, including cyber security threats to gain unauthorized access to sensitive information, render data or systems unusable or otherwise disrupt our business operations, and threats to the security of our or third parties facilities and infrastructure, such as processing plants and pipelines. These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment, pollution or other environmental damage, disruptions to our operations and loss of sensitive confidential information. Moreover, in

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the event that one or more of these hazards occur, there can be no assurance that a response will be adequate to limit or reduce damage. As a result of these risks, we are also sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business. There can be no assurance that the insurance policies we maintain to limit our liability for such losses will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices or to cover all risks.

Our failure to develop, obtain or maintain the necessary infrastructure to successfully deliver gas to market may adversely affect our earnings, cash flows and results of operations.

Our delivery of gas depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing facilities. The capacity of transportation, gathering and processing facilities may be insufficient to accommodate potential production from existing and new wells. Competition for pipeline infrastructure within the region is intense, and many of our competitors have substantially greater financial resources than we do, which could affect our competitive position. The Company s investment in midstream infrastructure is intended to address a lack of capacity on, and access to, existing gathering and transportation pipelines as well as curtailments on such pipelines. Our infrastructure development and maintenance programs can involve significant risks, including those related to timing, cost overruns and operational efficiency, and these risks can be affected by the availability of capital, materials and qualified contractors and work force, as well as weather conditions, gas price volatility, government approvals, title and property access problems, geology, compliance by third parties with their contractual obligations to us and other factors. We also deliver to and are served by third-party gas transportation, gathering, processing and storage facilities which are limited in number, geographically concentrated and subject to the same risks identified above with respect to our infrastructure development and maintenance programs. Because we do not own these third-party pipelines or facilities, their continuing operation is not within our control. An extended interruption of access to or service from our or third-party pipelines and facilities for any reason, including cyber-attacks on such pipelines and facilities, could result in adverse consequences to us, such as delays in producing and selling our natural gas. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project. In addition, some of our third-party contracts may involve significant long-term financial commitments on our part. Moreover, our usage of third parties for transportation, gathering and processing services subjects us to the credit and performance risk of such third parties and may make us dependent upon those third parties to get our produced natural gas to market.

Also, our producing properties and operations are limited to the Appalachian Basin, making us vulnerable to risks associated with operating in limited geographic areas. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of gas produced from this area.

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 2014 business plan, we considered allocating capital and other resources to various aspects of our businesses, including well development (primarily drilling), reserve acquisitions, exploratory activities, midstream infrastructure, corporate items and other alternatives. We also considered our likely sources of capital and evaluated opportunities outside of the Appalachian Basin. 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, including the appropriate rate of reserve development, 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.

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We periodically engage in acquisitions, dispositions and other strategic transactions. These transactions involve various inherent risks, such as our ability to obtain the necessary regulatory approvals; the timing of and conditions imposed upon us by regulators in connection with such approvals; and our ability to achieve benefits anticipated to result from acquisition or disposition of the assets. In addition, various factors including prevailing market conditions could negatively impact the benefits we receive from transactions. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our earnings, cash flows and financial position.

Our need to comply with comprehensive, complex and sometimes unpredictable government regulations may increase our costs and limit our revenue growth, which may result in reduced earnings.

Our operations are regulated extensively at the federal, state and local levels. Laws, regulations and other legal requirements have increased the cost to plan, design, drill, install, operate and abandon wells, gathering and transmission systems and pipelines. Environmental, health and safety legal requirements govern discharges of substances into the air and water; the management and disposal of hazardous substances and wastes; the clean-up of contaminated sites; groundwater quality and availability; plant and wildlife protection; locations available for drilling and pipeline construction; environmental impact studies and assessments prior to permitting; restoration of drilling properties after drilling is completed; pipeline safety (including replacement requirements); and work practices related to employee health and safety. Compliance with the laws, regulations and other legal requirements applicable to our businesses may increase our cost of doing business or result in delays due to the need to obtain additional or more detailed governmental approvals and permits. These requirements could also subject us to claims for personal injuries, property damage and other damages. Our failure to comply with the laws, regulations and other legal requirements applicable to our businesses, even if as a result of factors beyond our control, could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and damages.

The rates charged to customers by our gathering, transportation and storage businesses are, in many cases, subject to federal regulation by the FERC, which may prohibit us from realizing a level of return which we believe is appropriate. These restrictions may take the form of imputed revenue credits, cost disallowances and/or expense deferrals.

Laws, regulations and other legal requirements are constantly changing, and implementation of compliant processes in response to such changes could be costly and time consuming. In addition to periodic changes to air, water and waste laws, as well as recent EPA initiatives to impose climate change-based air regulations on the industry, the U.S. Congress and various states have been evaluating climate-related legislation and other regulatory initiatives that would further restrict emissions of greenhouse gases, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of burning natural gas). Such restrictions may result in additional compliance obligations with respect to, or taxes on the release, capture and use of, greenhouse gases that could have an adverse effect on our operations.

Another area of potential regulation is hydraulic fracturing, which we utilize to complete most of our natural gas wells. Certain environmental and other groups have suggested that additional laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and legislation has been proposed or is under discussion at the federal and state levels. We cannot predict whether any such federal or state legislation or regulation will be enacted and, if enacted, how it may affect our operations, but enactment of additional laws or regulations could increase our operating costs.

Recent discussions regarding the federal budget have included proposals which could potentially increase and accelerate the payment of federal and collaterally state income taxes of independent producers with the potential repeal of the ability to expense intangible drilling costs having the most significant potential future impact to us. These changes, if enacted, will make it more costly for us to explore for and develop our natural gas resources.

The rates of federal, state and local taxes applicable to the industries in which we operate, including production taxes paid by EQT Production, which often fluctuate, could be increased by the various taxing authorities. In addition, the tax laws, rules and regulations that affect our business, such as the imposition of a new severance tax (a tax on the extraction of natural resources) in states in which we produce gas, could change. Any such increase or change could adversely impact our earnings, cash flows and financial position.

In July 2010, the U.S. Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivative market and entities, such as the Company, that participate in that market. The new legislation, known as the Dodd-Frank Act, required the CFTC, the SEC and other regulatory agencies to promulgate rules and regulations implementing the new legislation. As of the filing date of this Annual Report, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including the Company, such as recordkeeping and certain reporting obligations. Other rules that may be relevant to the Company or its counterparties have yet to be proposed or finalized and, in some cases, finalized rules have yet to be implemented. Because significant rules relevant to natural gas hedging activities are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the new regulations on the Company s hedging program, including available counterparties, or regulatory compliance obligations. The Company anticipates, however, increased compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

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 short-term bank and money markets and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by the cash flows 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 and our credit ratings.

Any downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to raise capital through the issuance of debt or equity securities or other borrowing arrangements, which could adversely affect our business, results of operations and liquidity. We cannot be sure that our current ratings will remain in effect for any given period of time or that our rating will not be lowered or withdrawn entirely by a rating agency. An increase in the level of our indebtedness in the future may result in a downgrade in the ratings that are assigned to our debt. Any downgrade in our ratings could result in an increase in our borrowing costs, which would diminish financial results.

Our failure to assess production opportunities based on market conditions could negatively impact our long-term growth prospects for our production business.

Our goal of sustaining long-term growth for our production business is contingent upon our ability to identify production opportunities based on market conditions. Our decision to drill a well is subject to a number of factors which may alter our drilling schedule or our plans to drill at all. We may have difficulty drilling all of the wells before the lease term expires which could result in the loss of certain leasehold rights, or we could drill wells in locations where we do not have the necessary infrastructure to deliver the gas to market. Successfully identifying production opportunities involves a high degree of business experience, knowledge and careful evaluation of potential opportunities, along with subjective judgments and assumptions which may prove to be incorrect. In addition, any exploration projects increase the risks inherent in our natural gas activities. Specifically, seismic data is subject to interpretation and may not accurately identify the presence of natural gas or other hydrocarbons, which could adversely affect the results of our operations. Because we have a limited operating history in certain areas, our future operating results may be difficult to forecast, and our failure to sustain high growth rates in the future could adversely affect the market price of our common stock.

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The amount and timing of actual future gas production is difficult to predict and may vary significantly from our estimates, which may reduce our earnings.

Our future success depends upon our ability to develop additional gas reserves that are economically recoverable and to optimize existing well production, and our failure to do so may reduce our earnings. Our drilling and subsequent maintenance of wells can involve significant risks, including those related to timing, cost overruns and operational efficiency, and these risks can be affected by the availability of capital, leases, rigs, equipment, a qualified work force, and adequate capacity for the treatment and recycling or disposal of waste water generated in our operations, as well as weather conditions, gas price volatility, government approvals, title and property access problems, geology, equipment failure or accidents and other factors. Drilling for natural gas can be unprofitable, not only from dry wells, but from productive wells that do not produce sufficient revenues to return a profit. Additionally, a failure to effectively and efficiently operate existing wells may cause production volumes to fall short of our projections. Without continued successful development or acquisition activities, together with effective operation of existing wells, our reserves and revenues will decline as a result of our current reserves being depleted by production.

We also rely on third parties for certain construction, drilling and completion services, materials and supplies. Delays or failures to perform by such third parties could adversely impact our earnings, cash flows and financial position.

The loss of key personnel could adversely affect our ability to execute our strategic, operational and financial plans.

Our operations are dependent upon 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, the success of our operations will depend, in part, on our ability to attract, develop and retain experienced personnel. There is competition within our industry for experienced technical personnel and certain other professionals, which could increase the costs associated with attracting and retaining such personnel. If we cannot attract, develop and retain our technical and professional personnel or attract additional experienced technical and professional personnel, our ability to compete could be harmed.

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, oil spills, the explosion of natural gas transmission lines and concerns raised by advocacy groups about hydraulic fracturing, may lead to increased regulatory scrutiny which may, in turn, lead to new local, 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.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated natural gas and oil reserves.

You should not assume that the standardized measure of discounted 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 based the discounted future net cash flows from our proved reserves on the twelve month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our properties will be affected by factors such as the actual prices we receive for natural gas, NGLs and oil and the amount, timing and cost of actual production. In addition, the 10% discount factor we use when calculating standardized measure 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 natural gas, NGL and oil industry in general.

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Our proved reserves are estimates that are based upon many assumptions that may prove to be inaccurate. Any significant change in these underlying assumptions will greatly affect the quantities and present value of our reserves.

Reserve engineering is a subjective process involving estimates of underground accumulations of natural gas, NGLs and oil and assumptions concerning future prices, production levels and operating and development costs. These estimates and assumptions are inherently imprecise. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any significant variance from our assumptions could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas, NGLs and oil, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas, NGLs and oil we ultimately recover being different from our reserve estimates.

See Item 7A, Quantitative and Qualitative Disclosures About Market Risk, for further discussion regarding the Company s exposure to market risks, including the risks associated with our use of derivative contracts to hedge commodity prices.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Principal facilities are owned or, in the case of certain office locations, warehouse buildings and equipment, leased, by the Company s business segments. The majority of the Company s properties are located on or under (i) private properties owned in fee, held by lease or occupied under perpetual easements or other rights acquired for the most part without warranty of underlying land titles or (ii) public highways under franchises or permits from various governmental authorities. The Company s facilities are generally well maintained and, where appropriate, are replaced or expanded to meet operating requirements.

EQT Production: EQT Production s properties are located primarily in Pennsylvania, West Virginia, Ohio, Kentucky and Virginia. This segment has approximately 3.6 million gross acres (approximately 63% of which are considered undeveloped), which encompass substantially all of the Company s acreage of proved developed and undeveloped natural gas and oil producing properties. Approximately 580,000 of these gross acres are located in the Marcellus play. Although most of its wells are drilled to relatively shallow depths (2,000 to 8,000 feet below the surface), the Company retains what are normally considered deep rights on the majority of its acreage. As of December 31, 2013, the Company estimated its total proved reserves to be 8.3 Tcfe, consisting of proved developed producing reserves of 3.8 Tcfe, proved developed non-producing reserves of 0.2 Tcfe and proved undeveloped reserves of 4.4 Tcfe. Substantially all of the Company s reserves reside in continuous accumulations.

The Company s estimate of proved natural gas, NGL and oil reserves is prepared by Company engineers. The engineer primarily responsible for preparing the reserve report and the technical aspects of the reserves audit received a bachelor s degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University and has 25 years of experience in the oil and gas industry. To ensure that the reserves are materially accurate, management reviews the price, heat content conversion rate and cost assumptions used in the economic model to determine the reserves. Additionally, division of interest and production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems, and the reserve reconciliation between prior year reserves and current year reserves is reviewed by senior management.

The Company s estimate of proved natural gas, NGL and oil reserves is audited by the independent consulting firm of Ryder Scott Company, L.P. (Ryder Scott), which is hired by the Company s management. Since 1937, Ryder Scott has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally. Ryder Scott reviewed 100% of the total net gas, NGL and oil proved reserves attributable to the Company s interests as of December 31, 2013. Ryder Scott conducted a detailed, well by well,

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audit of the Company s largest properties. This audit covered 80% of the Company s proved reserves. Ryder Scott s audit of the remaining 20% of the Company s properties consisted of an audit of aggregated groups not exceeding 200 wells per group. Ryder Scott s audit report has been filed herewith as Exhibit 99.01.

No report has been filed with any federal authority or agency reflecting a 5% or more difference from the Company s estimated total reserves. Additional information relating to the Company s estimates of natural gas, NGL and crude oil reserves and future net cash flows is provided in Note 21 (unaudited) to the Consolidated Financial Statements.

In 2013, the Company commenced drilling operations (spud or drilled) on 168 gross horizontal wells with an aggregate of approximately 830,000 feet of pay in the Marcellus play. Total proved reserves in the Marcellus play increased 44% to 6.2 Tcfe in 2013 primarily as a result of the Company s 2012 and 2013 drilling programs. In the Huron play, the Company spud 50 gross horizontal wells during 2013 with an aggregate of approximately 300,000 feet of pay. Total proved reserves in the Huron play (including vertical non-shale formations of 0.7 Tcfe) increased approximately 27% to 2.0 Tcfe, as the Company re-established development of the Huron play. The Company spud 7 wells in the Utica Shale in 2013 with an aggregate of approximately 42,000 feet of pay. Total proved reserves in the Utica play are less than 0.1 Tcfe. The Company did not drill any CBM wells in 2013. The CBM play had total proved reserves of 0.2 Tcfe at December 31, 2013, a slight increase from 2012. Production sales volumes in 2013 from the Marcellus, Huron and CBM plays were 275.0 Bcfe, 35.3 Bcfe and 12.4 Bcfe, respectively. Over the past three years, the Company has experienced a 99% developmental drilling success rate.

Natural gas, BTU premium, NGL and crude oil production and pricing:

[redacted]

NGLs and crude oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods. Information for periods prior to 2013 has been recast to reflect this conversion rate.

For additional information on production and pricing, see Consolidated Operational Data in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

The Company s average per unit production cost, excluding production taxes, of natural gas, NGLs and oil during 2013, 2012 and 2011 was $0.15, $0.17 and $0.20 per Mcfe, respectively. At December 31, 2013, the Company had approximately 50 multiple completion wells.

	Natural Gas	Oil
Total productive wells at December 31, 2013:		
Total gross productive wells	14,622	5
Total net productive wells	12,822	5
Total in-process wells at December 31, 2013:		
Total gross in-process wells	147	
Total net in-process wells	144	

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Summary of proved natural gas, oil and NGL reserves as of December 31, 2013 based on average fiscal year prices:

	Natural Gas (Mcf)	Oil and NGLs (Bbls)
Developed	3,567,313	69,729
Undeveloped	3,994,248	61,389
Total proved reserves	7,561,561	131,118

Total acreage at December 31, 2013:	
Total gross productive acres	1,339,773
Total net productive acres	1,192,127
Total gross undeveloped acres	2,277,568
Total net undeveloped acres	2,026,575

As of December 31, 2013, the Company did not have any reserves that have been classified as proved undeveloped reserves for more than five years.

Certain lease and acquisition agreements require the Company to drill a specific number of wells in 2014. A drilling obligation exists to drill 2 wells in the Lower Huron formation and approximately 20,000 gross undeveloped acres could expire if this obligation is not met. Within the Marcellus formation, the Company is required to drill three wells in 2014 and could incur the potential loss of leases for approximately 6,000 gross undeveloped acres if this obligation is not met. The Company intends to satisfy such requirements either directly through its 2014 development program or indirectly by contracting with a third party to do so, including through an assignment of the lease, farmout or other arrangement.

As of December 31, 2013, leases associated with approximately 28,000 gross undeveloped acres expire in 2014 if they are not renewed. This acreage is in addition to the acreage that may be lost if drilling obligations are not met. The Company has an active lease renewal program in areas targeted for development.

Number of net productive and dry exploratory and development wells drilled:

	For the Years Ended December 31,		
	2013	2012	2011
Exploratory wells:			
Productive			
Dry			
Development wells:			
Productive	223.2	128.5	211.2

Dry	1.0	1.0	2.0

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Selected data by state (as of December 31, 2013 unless otherwise noted):

	Kentucky	West Virginia	Virginia	Pennsylvania	Ohio	Total
Natural gas and oil production (MMcfe) 2013	52,208	95,843	22,056	196,250	755	367,112
Natural gas and oil production (MMcfe) 2012	59,891	81,534	23,438	96,100		260,963
Natural gas and oil production (MMcfe) 2011	61,402	53,742	25,581	58,096		198,821
Average net revenue interest (%)	95.5%	88.0%	49.9%	82.4%	72.7%	82.5%
Total gross productive wells	5,556	4,895	3,258	915	3	14,627
Total net productive wells	5,306	4,660	1,955	903	3	12,827
Total gross productive acreage	548,560	428,572	274,480	87,288	873	1,339,773
Total gross undeveloped acreage	924,650	799,409	246,228	287,998	19,283	2,277,568
Total gross acreage	1,473,210	1,227,981	520,708	375,286	20,156	3,617,341
Total net productive acreage	488,104	381,348	244,230	77,668	777	1,192,127
Total net undeveloped acreage	907,972	711,198	108,589	280,466	18,350	2,026,575
Total net acreage	1,396,076	1,092,546	352,819	358,134	19,127	3,218,702
(Amounts in Bcfe)						
Proved developed producing reserves	1,248	1,030	289	1,209	3	3,779
Proved developed non-producing reserves	8	83		116		207
Proved undeveloped reserves	198	1,650		2,513	1	4,362
Proved developed and undeveloped reserves	1,454	2,763	289	3,838	4	8,348
Gross proved undeveloped drilling locations	131	293		385	1	810
Net proved undeveloped drilling locations	131	293		383	1	808

The Company sells natural gas primarily within the Appalachian Basin under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves. As of December 31, 2013, the Company s delivery commitments through 2018 were as follows:

For the Year Ended December 31,	Natural Gas (Bcf)
2014	281
2015	150
2016	98
2017	74

2018	74

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Capital expenditures at EQT Production totaled $1,423 million during 2013, including $186 million for the acquisition of undeveloped property and Marcellus wells. The Company invested approximately $885 million during 2013 converting undeveloped reserves to developed reserves and approximately $352 million on wells still in progress at year end. During the year, the Company converted 653 Bcfe of proved undeveloped reserves to proved developed reserves. The Company had additions to proved developed reserves of 902 Bcfe, the majority of which were from wells spud that had not previously been classified as proved or were related to the inclusion of NGL reserves. New proved undeveloped reserves of 2,158 Bcfe were added during 2013. These reserve extensions and discoveries were mainly due to decreased lateral spacing in one of the Company s locations in Greene County, Pennsylvania, additional proved locations in the Company s Pennsylvania and West Virginia Marcellus play and the addition of Huron proved undeveloped reserves in Kentucky. This increase was partially offset by negative revisions of 349 Bcfe, which was primarily due to the removal of 58 undeveloped locations and their associated reserves. While the Company still plans to develop these reserves, projected development has been delayed beyond 5 years of their booking date. As of December 31, 2013, the Company s proved undeveloped reserves totaled 4.4 Tcfe, 95% of which is associated with the development of the Marcellus play. All proved undeveloped drilling locations are expected to be drilled within five years.

The Company s 2013 extensions, discoveries and other additions resulting from extensions of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery of 2,047 Bcfe exceeded the 2013 production of 367 Bcfe.

Wells located in Pennsylvania are primarily in Marcellus formations with depths ranging from 5,000 feet to 8,000 feet. Wells located in West Virginia are primarily in Marcellus and Huron formations with depths ranging from 2,500 feet to 6,500 feet. Wells located in Kentucky are primarily in Huron formations with depths ranging from 2,500 feet to 6,000 feet. Wells located in Virginia are primarily in CBM formations with depths ranging from 2,000 feet to 3,000 feet. Wells located in Ohio are in the Utica Shale formation with depths ranging from 6,500 feet to 7,000 feet.

EQT Production owns and leases office space in Pennsylvania, West Virginia, Virginia and Kentucky.

EQT Midstream: EQT Midstream owns or operates approximately 9,450 miles of gathering lines and 218 compressor units with approximately 250,000 horsepower of installed capacity, as well as other general property and equipment.

	Kentucky	**West Virginia**	**Virginia**	**Pennsylvania**	**Total**
Approximate miles of gathering lines	3,550	4,100	1,600	200	9,450

Substantially all of the gathering operation s sales volumes are delivered to several large interstate pipelines on which the Company and other customers lease capacity. These pipelines are subject to periodic curtailments for maintenance and repairs.

EQT Midstream also operates a FERC-regulated transmission and storage system. These operations consist of an approximately 900 mile FERC-regulated interstate pipeline system that connects to seven interstate pipelines and multiple distribution companies. The system is supported by eighteen associated natural gas storage reservoirs with approximately 660 MMcf per day of peak delivery capability and 47 Bcf of working gas capacity. The transmission and storage system stretches throughout north central West Virginia and southwestern Pennsylvania.

EQT Midstream owns and leases office space in Pennsylvania, West Virginia, Virginia and Kentucky.

Headquarters: The corporate headquarters and other operations are located in leased office space in Pittsburgh, Pennsylvania.

See Capital Resources and Liquidity in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, for a discussion of capital expenditures.

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Item 3. Legal Proceedings

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company and its subsidiaries. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company accrues legal or other direct costs related to loss contingencies when actually incurred. The Company has established reserves it believes to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, the Company believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the financial position, results of operations or liquidity of the Company.

The Company has received a number of Notices of Violation (NOVs) from environmental agencies in some of the states in which we operate alleging various violations of oil and gas, air, water and waste regulations. The Company has responded to these NOVs and has generally corrected or remediated the areas in question. The Company disputes a number of the alleged NOVs and cannot predict with certainty whether any or all of these NOVs will result in penalties. If penalties are imposed, an individual penalty or the aggregate of these penalties could result in monetary sanctions in excess of $100,000.

Item 4. Mine Safety and Health Administration Data

Not Applicable.

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Executive Officers of the Registrant (as of February 20, 2014)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Theresa Z. Bone (50)	Vice President, Finance and Chief Accounting Officer (2007)	Elected to present position October 2013; Vice President and Corporate Controller from July 2007 to October 2013. Ms. Bone is also Vice President, Finance and Chief Accounting Officer of EQT Midstream Services, LLC, the general partner of the Partnership, the Company s publicly-traded master limited partnership, since October 2013. Ms. Bone was Vice President and Principal Accounting Officer of EQT Midstream Services, LLC from January 2012 to October 2013.
Philip P. Conti (54)	Senior Vice President and Chief Financial Officer (2000)	Elected to present position February 2007. Mr. Conti is also Senior Vice President, Chief Financial Officer and a Director of EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
Randall L. Crawford (51)	Senior Vice President and President, Midstream and Commercial (2003)	Elected to present position December 2013; Senior Vice President and President, Midstream, Distribution and Commercial from April 2010 to December 2013; Senior Vice President and President, Midstream and Distribution from January 2008 to April 2010. Mr. Crawford is also Executive Vice President, Chief Operating Officer and a Director of EQT Midstream Services, LLC, the general partner of the Partnership, since December 2013. Mr. Crawford was Executive Vice President and a Director of EQT Midstream Services, LLC from January 2012 through December 2013.
Lewis B. Gardner (56)	General Counsel and Vice President, External Affairs (2008)	Elected to present position March 2008; Managing Director, External Affairs and Labor Relations from January 2008 to March 2008. Mr. Gardner is also a Director of EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
Charlene Petrelli (53)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007.
David L. Porges (56)	Chairman, President and Chief Executive Officer (1998)	Elected to present position May 2011; President, Chief Executive Officer and Director from April 2010 to May 2011; President, Chief Operating Officer and Director from February 2007 to April 2010. Mr. Porges is also Chairman, President and Chief Executive Officer of EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
Steven T. Schlotterbeck (48)	Executive Vice President and President, Exploration and Production (2008)	Elected to present position December 2013; Senior Vice President and President, Exploration and Production from April 2010 to December 2013; Vice President and President, Production from January 2008 to April 2010.

All executive officers have executed agreements with the Company and serve at the pleasure of the Company s Board of Directors. Officers are elected annually to serve during the ensuing year or until their successors are chosen and qualified.

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PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company s common stock is listed on the New York Stock Exchange. The high and low sales prices reflected in the New York Stock Exchange Composite Transactions and the dividends declared and paid per share, for 2013 and 2012 are summarized as follows (in U.S. dollars per share):

	2013			2012		
	High	Low	Dividend	High	Low	Dividend
1st Quarter	$ 68.44	$ 56.84	$ 0.03	$ 56.56	$ 46.04	$ 0.22
2nd Quarter	84.00	64.71	0.03	55.20	43.69	0.22
3rd Quarter	94.42	78.57	0.03	59.46	52.20	0.22
4th Quarter	91.59	80.72	0.03	62.74	56.45	0.22

As of January 31, 2014, there were 2,817 shareholders of record of the Company s common stock.

The amount and timing of dividends is subject to the discretion of the Board of Directors and depends upon business conditions, such as the Company s lines of business, results of operations and financial conditions, strategic direction and other factors. During 2012, the Company paid a dividend at an annual rate of $0.88 per share. In December 2012, concurrent with the announcement of entering into a definitive agreement to transfer Equitable Gas and Homeworks to PNG Companies, the Company announced a new annual dividend rate, effective January 2013, of $0.12 per share, which the Company believed better reflects the blend of the Company s core businesses remaining after the closing of the Equitable Gas Transaction a dividend supporting midstream business and a capital-intensive, rapidly growing production business. The Board of Directors has the discretion to change the annual dividend rate at any time for the reasons described above.

The following table sets forth the Company s repurchases of equity securities registered under Section 12 of the Securities Exchange Act of 1934, as amended, that have occurred in the three months ended December 31, 2013:

Period	Total number of shares (or units) purchased (a)	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 2013 (October 1 October 31)				
November 2013 (November 1 November 30)	1,301	$ 85.11		

December 2013 (December 1 December 31)	7,456	$	85.84
Total	8,757	$	85.73

(a) Reflects shares withheld by the Company to pay taxes upon vesting of restricted stock.

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Stock Performance Graph

The following graph compares the most recent five-year cumulative total return attained by holders of the Company s common stock with the cumulative total returns of the S&P 500 Index and two customized peer groups of 25 companies. The individual companies of the prior customized peer group (the Old Self-Constructed Peer Group) and the new customized peer group (the New Self-Constructed Peer Group) are listed below in footnotes (a) and (b), respectively. An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2008 in the Company s common stock, in the S&P 500 Index and in each customized peer group. Relative performance is tracked through December 31, 2013.

	12/08	**12/09**	**12/10**	**12/11**	**12/12**	**12/13**
EQT Corporation	**100.00**	**133.93**	**139.76**	**173.54**	**189.90**	**289.52**
S&P 500	**100.00**	**126.46**	**145.51**	**148.59**	**172.37**	**228.19**
Old Self-Constructed Peer Group (a)	**100.00**	**154.37**	**168.84**	**177.81**	**183.02**	**249.07**
New Self-Constructed Peer Group (b)	**100.00**	**164.57**	**190.38**	**195.44**	**199.73**	**277.94**

(a) The Old Self-Constructed Peer Group, first used in the Company s Annual Report on Form 10-K for the year ended December 31, 2011, includes 25 companies, which are: Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., CONSOL Energy Inc., Energen Corporation, EOG Resources, Inc., EXCO Resources, Inc., MarkWest Energy Partners, L.P., MDU Resources Group, Inc., National Fuel Gas Company, NSTAR, ONEOK, Inc., Penn Virginia Corporation, Pioneer Natural Resources Company, Plains Exploration & Production Company, Questar Corporation, Quicksilver Resources Inc., Range Resources Corporation, Sempra Energy, SM Energy Company, Southwestern Energy Company, Spectra Energy Corp, Ultra Petroleum Corp., Whiting Petroleum Corporation and The Williams Companies, Inc. NSTAR was acquired during 2012 and is included in the calculation from December 31, 2008 through December 31, 2011, at which time it was removed from the peer group calculation. Plains Exploration & Production Company was acquired during 2013 and is included in the calculation from December 31, 2008 through December 31, 2012, at which time it was removed from the peer group calculation.

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(b) The New Self-Constructed Peer Group includes 25 companies, which are: Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Concho Resources, Inc., CONSOL Energy Inc., Continental Resources, Inc., Energen Corporation, EOG Resources, Inc., EXCO Resources, Inc., MarkWest Energy Partners, L.P., National Fuel Gas Company, Newfield Exploration Company, Noble Energy, Inc., ONEOK, Inc., Pioneer Natural Resources Company, QEP Resources, Inc., Questar Corporation, Quicksilver Resources Inc., Range Resources Corporation, SM Energy Company, Southwestern Energy Company, Spectra Energy Corp, Ultra Petroleum Corp., Whiting Petroleum Corporation and The Williams Companies, Inc. QEP Resources, Inc. completed its IPO in 2010 and is included in the calculation from July 1, 2010, the date when its common stock began trading on the New York Stock Exchange, through December 31, 2013.

The Company s management selected the New Self-Constructed Peer Group because it believes these companies are better aligned with the Company s production and midstream businesses after the transfer of Equitable Gas to PNG Companies in December 2013. The New Self-Constructed Peer Group is also the same peer group used for the Company s 2014 Executive Performance Incentive Program, which utilizes three-year total shareholder return against the peer group as one performance metric.

See Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholders Matters, for information relating to compensation plans under which the Company s securities are authorized for issuance.

Item 6. Selected Financial Data

	As of and for the Years Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
	(Thousands, except per share amounts)				
Operating revenues	$ 1,862,011	$ 1,377,222	$ 1,323,829	$ 1,038,240	$ 849,006
Amounts attributable to EQT Corporation:					
Income from continuing operations	$ 298,729	$ 135,902	$ 419,582	$ 164,761	$ 81,153
Net income	$ 390,572	$ 183,395	$ 479,769	$ 227,700	$ 156,929
Earnings per share of common stock attributable to EQT Corporation:					
Basic:					
Income from continuing operations	$ 1.98	$ 0.91	$ 2.81	$ 1.14	$ 0.62
Net income	$ 2.59	$ 1.23	$ 3.21	$ 1.58	$ 1.20
Diluted:					
Income from continuing operations	$ 1.97	$ 0.90	$ 2.79	$ 1.14	$ 0.62
Net income	$ 2.57	$ 1.22	$ 3.19	$ 1.57	$ 1.19
Total assets	$ 9,792,053	$ 8,849,862	$ 8,772,719	$ 7,098,438	$ 5,957,257
Long-term debt	$ 2,501,516	$ 2,526,173	$ 2,746,942	$ 1,949,200	$ 1,949,200
Cash dividends declared per share of common stock	$ 0.12	$ 0.88	$ 0.88	$ 0.88	$ 0.88

Equitable Gas and Homeworks comprised substantially all of the Company s previously reported Distribution segment. The financial information of Equitable Gas and Homeworks is reflected as discontinued operations in this Annual Report on Form 10-K. All prior periods presented in this Annual Report have been recast to reflect the presentation of discontinued operations. See Item 1A, Risk Factors , Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Notes 2, 7 and 8 to the Consolidated Financial Statements for a discussion of matters that affect the comparability of the selected financial data as well as uncertainties that might affect the Company s future financial condition.

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Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

Consolidated Results of Continuing Operations

2013 EQT highlights included:

- Annual production sales volumes of 378.2 Bcfe, 43.0% higher than 2012
- Marcellus sales volumes of 275.0 Bcfe, 81.6% higher than 2012
- Gathered volumes of 466.4 TBtu, 39.1% higher than 2012
- Increased proved reserves by 39% to 8.3 Tcfe
- Completed an underwritten public offering of common units representing limited partner interests in the Partnership
- Completed the Equitable Gas Transaction

Income from continuing operations attributable to EQT Corporation for 2013 was $298.7 million, $1.97 per diluted share, compared with $135.9 million, $0.90 per diluted share, in 2012. The $162.8 million increase in income from continuing operations attributable to EQT Corporation between periods was primarily attributable to a 43% increase in natural gas volumes sold, increases in contracted transmission capacity and throughput and gathered volumes, the disposal of certain energy marketing contracts by EQT Energy in December 2013 and lower interest expense. These factors were partially offset by higher depreciation, depletion and amortization (DD&A) expense, higher income tax expense, higher selling, general and administrative (SG&A) expense and higher net income attributable to noncontrolling interests of the Partnership.

Operating income was $654.6 million in 2013 compared to $389.6 million in 2012, an increase of $265.0 million. The increase in operating income was attributable to a 43% increase in natural gas volumes sold, increased transmission pipeline revenues and gathered volumes and a $19.6 million pre-tax gain from the disposal of customer contracts by EQT Energy, partially offset by higher DD&A expense and higher SG&A expense.

Production sales volumes increased primarily as a result of increased production from the 2012 and 2013 drilling programs in the Marcellus acreage. This increase was partially offset by the normal production decline in the Company s producing wells. The average effective sales price to EQT Corporation for production sales volumes was $4.13 per Mcfe in 2013 compared to $4.17 per Mcfe in 2012. The average NYMEX natural gas index price increased to $3.65 per Mcf in 2013 from $2.79 per Mcf for 2012. Hedging activities resulted in an increase in the effective sales price of $0.36 per Mcf in 2013 compared to $1.10 per Mcf in 2012. The $0.74 per Mcf decrease in the impact of hedging activities in 2013 was the result of the differential in the NYMEX natural gas index prices between periods and the lower average hedge prices in 2013. Gathering net operating revenues increased due to a 39% increase in gathered volumes, partially offset by a 17% decrease in the average gathering fee. The gathered volume increase was driven by higher volumes gathered for EQT Production in the Marcellus play. The decrease in the average gathering fee resulted from increased gathered volumes in the Marcellus play, as the Marcellus gathering rate is lower than the rate in other areas.

Operating expenses for 2013 were $1,227.0 million compared to $987.6 million in 2012, an increase of $239.4 million. This increase was primarily attributable to higher DD&A charges attributable to higher production volumes at a production depletion rate of $1.50 per Mcfe compared to $1.52 per Mcfe in 2012 and higher production-related and SG&A costs consistent with the growth in the production and midstream businesses.

On July 22, 2013, the Partnership completed an underwritten public offering of 12,650,000 common units representing limited partner interests in the Partnership. Following the offering and the closing of the Sunrise Merger, the Company holds a 44.6% equity interest in the Partnership, which includes 3,443,902 common units, 17,339,718 subordinated units and a 2% general partner interest. The Partnership received net proceeds of $529.4 million from the offering, after deducting the underwriters discount and offering expenses of $20.9 million. The Company continues to consolidate the results of the Partnership. The Company records the noncontrolling interest of the public limited partners in its financial statements.

On December 17, 2013, the Company and its wholly-owned subsidiary, Holdco, completed the previously announced transactions contemplated by the Master Purchase Agreement, pursuant to which the Company and Holdco

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transferred 100% of their ownership interests in Equitable Gas and Homeworks to PNG Companies. As consideration for the transaction, the Company received a cash payment of $740.6 million, which is subject to certain post-closing adjustments, select midstream assets, including the AVC facilities, with a preliminary estimated fair value of approximately $141.4 million and other contractual assets with a preliminary estimated fair value of $32.5 million.

Income from continuing operations attributable to EQT Corporation for 2012 was $135.9 million, $0.90 per diluted share, compared with $419.6 million, $2.79 per diluted share, in 2011. In 2011, the Company recorded $202.9 million of pre-tax gains on dispositions related to the sales of the Big Sandy Pipeline (Big Sandy) and Langley. The Company was negatively impacted in 2012 by lower realized sales prices for production sales volumes, higher DD&A expense and higher interest expense partially offset by increases in both production and gathered volumes and lower income tax expense.

Operating income was $389.6 million in 2012 compared to $761.2 million in 2011, a decrease of $371.6 million. In addition to the $202.9 million pre-tax gain in 2011 on the dispositions of Big Sandy and Langley, the decrease from 2011 was a result of approximately 24% lower realized sales prices for production sales volumes, a 22% higher production depletion rate and higher other operating expenses, partially offset by a 33% increase in production volumes, a 30% increase in gathering volumes and higher transmission revenues.

Production sales volumes increased primarily as a result of increased production from the 2011 and 2012 drilling programs in the Marcellus acreage. This increase was partially offset by the normal production decline in the Company s producing wells. The average effective sales price to EQT Corporation including the effect of the Company s hedging program was $4.17 per Mcfe in 2012 compared to $5.23 per Mcfe in 2011. Hedging activities resulted in an increase in the average natural gas sales price of $1.10 per Mcf in 2012 and $0.51 per Mcf in 2011. Gathering net operating revenues increased due to a 30% increase in gathered volumes, partially offset by a 7% decrease in the average gathering fee. The gathered volume increase was driven by higher volumes gathered for EQT Production in the Marcellus play.

Operating expenses for 2012 were $987.6 million compared to $765.6 million in 2011, an increase of $222.0 million. This increase was primarily attributable to higher DD&A charges from higher production volumes at a production depletion rate of $1.52 per Mcfe compared to $1.25 per Mcfe in 2011 and higher production-related and SG&A costs consistent with the growth in the production and midstream businesses.

On July 2, 2012, the Partnership completed its IPO of 14,375,000 common units representing limited partner interests in the Partnership, which represented 40.6% of the Partnership s outstanding equity. The Company retained a 59.4% equity interest in the Partnership, including 2,964,718 common units, 17,339,718 subordinated units and a 2% general partner interest.

See Other Income Statement Items for a discussion of other income, interest expense, income taxes, income from discontinued operations and net income attributable to noncontrolling interests, and Investing Activities in Capital Resources and Liquidity for a discussion of capital expenditures.

Consolidated Operational Data

Revenues earned by the Company at the wellhead from the sale of natural gas are split between EQT Production and EQT Midstream. The split is reflected in the calculation of EQT Production s average effective sales price. The following operational information presents detailed gross liquid and natural gas operational information as well as midstream deductions to assist in the understanding of the Company s consolidated operations.

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in thousands (unless noted)	Years Ended December 31, 2013	2012	2011
LIQUIDS			
NGLs:			
Sales Volume (MMcfe) (a)	27,860	18,981	16,541
Sales Volume (Mbbls)	4,643	3,163	2,757
Gross Price ($/Bbl)	$ 45.58	$ 49.29	$ 67.41
Gross NGL Revenue	$ 211,626	$ 155,926	$ 185,845
BTU Premium (Ethane sold as natural gas):			
Sales Volume (MMBtu)	29,185	22,494	16,124
Price ($/MMBtu)	$ 3.66	$ 2.83	$ 4.04
BTU Premium Revenue	$ 106,724	$ 63,668	$ 65,168
Oil:			
Sales Volume (MMcfe) (a)	1,620	1,587	1,248
Sales Volume (Mbbls)	270	264	208
Net Price ($/Bbl)	$ 85.82	$ 83.95	$ 81.58
Net Oil Revenue	$ 23,171	$ 22,161	$ 16,968
Total Liquids Revenue	$ 341,521	$ 241,755	$ 267,981
GAS			
Sales Volume (MMcf)	348,693	243,886	181,566
NYMEX Price ($/Mcf) (b)	$ 3.66	$ 2.83	$ 4.04
Gas Revenue	$ 1,277,847	$ 690,293	$ 733,814
Basis	(51,274)	(960)	24,047
Gross Gas Revenue (unhedged)	$ 1,226,573	$ 689,333	$ 757,861
Total Gross Gas & Liquids Revenue (unhedged)	$ 1,568,094	$ 931,088	$ 1,025,842
Hedge impact (c)	137,634	290,557	101,047
Total Gross Gas & Liquids Revenue	$ 1,705,728	$ 1,221,645	$ 1,126,889
Total Sales Volume (MMcfe)	378,173	264,454	199,355
Average hedge adjusted price ($/Mcfe)	$ 4.51	$ 4.62	$ 5.65
Midstream Revenue Deductions ($ / Mcfe)			
Gathering to EQT Midstream	$ (0.82)	$ (1.00)	$ (1.08)
Transmission to EQT Midstream	(0.23)	(0.19)	(0.21)
Third-party gathering and transmission (d)	(0.28)	(0.35)	(0.30)
Third-party processing	(0.10)	(0.10)	(0.12)
Total midstream revenue deductions	(1.43)	(1.64)	(1.71)
Average effective sales price to EQT Production	$ 3.08	$ 2.98	$ 3.94
EQT Revenue ($ / Mcfe)			
Revenues to EQT Midstream	$ 1.05	$ 1.19	$ 1.29
Revenues to EQT Production	3.08	2.98	3.94
Average effective sales price to EQT Corporation	$ 4.13	$ 4.17	$ 5.23

(a) NGLs and crude oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods. Information for periods prior to 2013 has been recast to reflect this conversion rate.

(b) The Company s volume weighted NYMEX natural gas price (actual average NYMEX natural gas price ($/Mcf) was $3.65, $2.79 and $4.04 for the years ended December 31, 2013, 2012 and 2011, respectively).

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(c) Includes gains or losses related to the sale of fixed price natural gas. The hedge impact also included a loss for hedging ineffectiveness of $21.5 million, $0.06 per Mcfe, for the year ended December 31, 2013. Hedging ineffectiveness did not impact the effective sales price for the years ended December 31, 2012 or 2011.

(d) Due to the sale of unused capacity on the El Paso 300 line that was not under long-term resale agreements at prices below the capacity charge, third-party gathering and transmission rates increased by $0.05 per Mcfe and $0.04 per Mcfe for the years ended December 31, 2013 and 2012, respectively. In 2011, the unused capacity on the El Paso 300 line not under long-term resale agreements was sold at prices above the capacity charge, decreasing third-party gathering and transmission rates by $0.03 per Mcfe.

Business Segment Results of Operations

Business segment operating results from continuing operations are presented in the segment discussions and financial tables on the following pages. Operating segments are evaluated on their contribution to the Company s consolidated results based on operating income. Other income, interest and income taxes are managed on a consolidated basis. Headquarters costs are billed to the operating segments based upon a fixed allocation of the headquarters annual operating budget. Differences between budget and actual headquarters expenses totaling $45.4 million, $35.6 million and $42.5 million were not allocated to the operating segments for the years ended December 31, 2013, 2012 and 2011, respectively. Unallocated expenses consist primarily of incentive compensation, administrative costs and corporate overhead charges previously allocated to the Distribution segment that were reclassified to Headquarters as part of the recast of this Annual Report on Form 10-K to reflect the discontinued operations presentation.

The Company has reported the components of each segment s operating income from continuing operations and various operational measures in the sections below, and where appropriate, has provided information describing how a measure was derived. EQT s management believes that presentation of this information provides useful information to management and investors regarding the financial condition, operations and trends of each of EQT s business segments without being obscured by the financial condition, operations and trends for the other segments or by the effects of corporate allocations of interest, income taxes and other income. In addition, management uses these measures for budget planning purposes. The Company s management reviews and reports the EQT Production segment results for operating revenues and purchased gas costs with transportation costs reflected as a deduction from operating revenues as management believes this presentation provides a more useful view of net effective sales price and is consistent with industry practices. Third-party transportation costs are reported as a component of purchased gas costs in the consolidated results. The Company has reconciled each segment s operating income to the Company s consolidated operating income and net income in Note 4 to the Consolidated Financial Statements.

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EQT Production

Results of Operations

	Years Ended December 31, 2013	2012	% change 2013 - 2012	2011	% change 2012 - 2011
OPERATIONAL DATA					
Sales volume detail (MMcfe):					
Horizontal Marcellus Play (a)	275,029	151,430	81.6	81,908	84.9
Horizontal Huron Play	35,255	41,985	(16.0)	44,737	(6.2)
CBM Play	12,429	13,084	(5.0)	13,682	(4.4)
Other	55,460	57,955	(4.3)	59,028	(1.8)
Total production sales volumes (b)	378,173	264,454	43.0	199,355	32.7
Average daily sales volumes (MMcfe/d)	1,036	723	43.3	546	32.4
Average effective sales price to EQT Production ($/Mcfe)	$ 3.08	$ 2.98	3.4	$ 3.94	(24.4)
Lease operating expenses (LOE), excluding production taxes ($/Mcfe)	$ 0.15	$ 0.17	(11.8)	$ 0.20	(15.0)
Production taxes ($/Mcfe) (c)	$ 0.13	$ 0.16	(18.8)	$ 0.20	(20.0)
Production depletion ($/Mcfe)	$ 1.50	$ 1.52	(1.3)	$ 1.25	21.6
DD&A (thousands):					
Production depletion	$ 568,990	$ 401,456	41.7	$ 248,286	61.7
Other DD&A	9,651	8,172	18.1	8,858	(7.7)
Total DD&A (thousands)	$ 578,641	$ 409,628	41.3	$ 257,144	59.3
Capital expenditures (thousands) (d)	$ 1,423,185	$ 991,775	43.5	$ 1,087,840	(8.8)
FINANCIAL DATA (thousands)					
Total net operating revenues	$ 1,168,657	$ 793,773	47.2	$ 791,285	0.3
Operating expenses:					
LOE, excluding production taxes	57,110	46,212	23.6	40,369	14.5
Production taxes (c)	50,981	49,943	2.1	40,542	23.2
Exploration expense	18,483	10,370	78.2	4,932	110.3
SG&A	92,197	89,707	2.8	61,200	46.6
DD&A	578,641	409,628	41.3	257,144	59.3
Total operating expenses	797,412	605,860	31.6	404,187	49.9
Operating income	$ 371,245	$ 187,913	97.6	$ 387,098	(51.5)

(a) Includes Upper Devonian wells.

(b) NGLs and crude oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods. Information for periods prior to 2013 has been recast to reflect this conversion rate.

(c) Production taxes include severance and production-related ad valorem and other property taxes and the Pennsylvania impact fee. The Pennsylvania impact fee for the year ended December 31, 2012 totaled

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$15.3 million, of which $6.7 million represented the retroactive fee for pre-2012 Marcellus wells. The production taxes unit rate for the year ended December 31, 2012 excludes the impact of the accrual for pre-2012 Marcellus wells.

(d) Includes $114.2 million of capital expenditures for the purchase of acreage and Marcellus wells from Chesapeake Energy Corporation and its partners (Chesapeake) during the year ended December 31, 2013 and $92.6 million of liabilities assumed in exchange for producing properties as part of the Appalachian NPI, LLC (ANPI) transaction described in Note 8 to the Consolidated Financial Statements during the year ended December 31, 2011.

Year Ended December 31, 2013 vs. December 31, 2012

EQT Production s operating income totaled $371.2 million for 2013 compared to $187.9 million for 2012. The $183.3 million increase in operating income was primarily due to increased sales of produced natural gas and NGLs and a higher average effective sales price partially offset by an increase in operating expenses.

Total operating revenues were $1,168.7 million for 2013 compared to $793.8 million for 2012. The $374.9 million increase in operating revenues was primarily due to a 43% increase in production sales volumes and a 3% increase in the average effective sales price to EQT Production. The increase in production sales volumes was the result of increased production from the 2011 and 2012 drilling programs, primarily in the Marcellus play. This increase was partially offset by the normal production decline in the Company s producing wells. The $0.10 per Mcfe increase in the average effective sales price to EQT Production was the net result of a 31% increase in the average NYMEX natural gas price, an increase in margins from fixed priced sales and lower midstream charges and gathering rates substantially offset by a smaller hedge gain and lower NGL and basis prices compared to 2012. The average effective sales price was impacted unfavorably in 2013 by $0.06 per Mcfe as a result of a loss on ineffectiveness of financial hedges of $21.5 million which was caused by the change in basis. The average effective sales price was impacted unfavorably in 2012 by $0.03 per Mcfe as a result of an $8.2 million adjustment to recognize financial instrument put premiums which should have been recorded ratably over 2010 and 2011.

Operating expenses totaled $797.4 million for 2013 compared to $605.9 million for 2012. The increase in operating expenses was the result of increases in DD&A, LOE, exploration expenses, SG&A and production taxes. Depletion expense increased as a result of higher production sales volumes in 2013 partially offset by a slightly lower overall depletion rate. The increase in LOE was mainly a result of increased Marcellus activity in 2013, including a $6.5 million increase in salt water disposal expenses and a $3.1 million increase in labor expenses in that region. The increase in exploration expense was due to increased impairments of unproved lease acreage of $8.7 million resulting from lease expirations during 2013, slightly offset by a reduction in geophysical activity compared to the prior year. SG&A expense increased in 2013 primarily as a result of higher personnel costs of $4.6 million, including incentive compensation expenses, and higher environmental reserves of $1.9 million partially offset by a decrease in franchise taxes of $2.2 million.

Production taxes increased primarily due to an increase in severance and property taxes related to higher market sales prices and higher production sales volumes. Severance and property taxes were offset by a $3.1 million decrease in the Pennsylvania impact fee. During 2013, the Pennsylvania impact fee was $12.2 million compared to $15.3 million in 2012, of which $6.7 million represented a retroactive fee for pre-2012 Marcellus wells.

Year Ended December 31, 2012 vs. December 31, 2011

EQT Production s operating income totaled $187.9 million for 2012 compared to $387.1 million for 2011. The $199.2 million decrease in operating income was primarily due to a lower average effective sales price and an increase in operating expenses partially offset by increased sales of produced natural gas and NGLs.

Total operating revenues were $793.8 million for 2012 compared to $791.3 million for 2011. The $2.5 million increase in operating revenues was primarily due to a 33% increase in production sales volumes which offset a 24% decrease in the average effective sales price to EQT Production. The increase in production sales volumes was primarily the result of increased production from the 2011 and 2012 drilling programs in the Marcellus play, as

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well as the acquisition of producing properties associated with the ANPI transaction in May 2011 which added 2.6 Bcfe of sales volumes in 2012. This increase was partially offset by the normal production decline in the Company s producing wells. The $0.96 per Mcfe decrease in the average effective sales price to EQT Production was primarily due to a 31% decrease in the average NYMEX gas price as well as lower basis and NGL prices, partially offset by higher hedging gains and lower affiliated gathering rates compared to 2011. The average effective sales price was also impacted unfavorably in 2012 by $0.03 per Mcfe as a result of an $8.2 million adjustment to recognize financial instrument put premiums which should have been recorded ratably over 2010 and 2011 and by $0.04 per Mcfe for the cost of transmission capacity on the El Paso 300 line, including long-term resale agreements. Management evaluated the size and nature of the put premium adjustment and concluded that the adjustment was not material to the financial statements.

Operating expenses totaled $605.9 million for 2012 compared to $404.2 million for 2011. The increase in operating expenses was the result of increases in DD&A, SG&A, production taxes, LOE and exploration expense. Depletion expense increased as a result of a higher overall depletion rate and higher produced volumes in 2012. The increase in the depletion rate was primarily due to an increase in costs to complete wells, higher capitalized overhead and interest costs and the removal of proved reserves due to lower natural gas prices and the suspension of drilling activity in the Huron play. The increase in SG&A was primarily a result of higher corporate overhead and commercial services allocations of $22.0 million, increased labor and relocation expenses of $4.0 million associated with increased Marcellus drilling and an increase in franchise taxes of $1.9 million.

In February 2012, the Commonwealth of Pennsylvania passed legislation imposing a natural gas impact fee. The legislation, which covers a significant portion of EQT s Marcellus Shale acreage, imposes an annual fee for a period of fifteen years on each well spud in Pennsylvania. The impact fee adjusts annually based on three factors: age of the well, changes in the Consumer Price Index and the average monthly NYMEX gas price. Production taxes increased primarily due to the Pennsylvania impact fee in 2012 of $15.3 million, of which $6.7 million represents the retroactive fee for pre-2012 Marcellus wells, as well as an increase in property taxes partially offset by a decrease in severance taxes due to the decrease in average effective sales price in 2012.

The increase in LOE was mainly a result of increased Marcellus activity in 2012 primarily related to a $3.0 million increase in salt water disposal expenses and a $2.1 million increase in labor expenses, as well as the elimination of $2.3 million of third-party operating expense reimbursements, as part of the ANPI transaction. Exploration expense increased in 2012 primarily due to increased impairments of unproved lease acreage of $3.0 million and also an increase in geophysical activity in 2012 related to the Ohio Utica formation.

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EQT Midstream

Results of Operations

	Years Ended December 31, 2013	2012	% change 2013 - 2012	2011	% change 2012 2011
OPERATIONAL DATA					
Gathered volumes (BBtu)	466,405	335,407	39.1	258,179	29.9
Average gathering fee ($/MMBtu)	$ 0.75	$ 0.90	(16.7)	$ 0.97	(7.2)
Gathering and compression expense ($/MMBtu) (a)	$ 0.18	$ 0.24	(25.0)	$ 0.30	(20.0)
Transmission pipeline throughput (BBtu)	418,360	221,944	88.5	159,384	39.3
Net operating revenues (thousands):					
Gathering	$ 351,410	$ 302,255	16.3	$ 249,607	21.1
Transmission	160,621	104,501	53.7	90,405	15.6
Storage, marketing and other	33,555	42,693	(21.4)	64,614	(33.9)
Total net operating revenues	$ 545,586	$ 449,449	21.4	$ 404,626	11.1
Capital expenditures (thousands)	$ 369,399	$ 375,731	(1.7)	$ 242,886	54.7
FINANCIAL DATA (thousands)					
Total operating revenues	$ 614,042	$ 505,498	21.5	$ 525,345	(3.8)
Purchased gas costs	68,456	56,049	22.1	120,719	(53.6)
Total net operating revenues	545,586	449,449	21.4	404,626	11.1
Operating expenses:					
Operating and maintenance	97,540	97,400	0.1	83,907	16.1
SG&A	63,850	49,943	27.8	49,901	0.1
DD&A	75,032	64,782	15.8	57,135	13.4
Total operating expenses	236,422	212,125	11.5	190,943	11.1
Gain on dispositions	19,618		100.0	202,928	(100.0)
Operating income	$ 328,782	$ 237,324	38.5	$ 416,611	(43.0)

(a) Gathering and compression expense per unit for the year ended December 31, 2011 excludes $7.1 million of favorable adjustments for certain non-income tax reserves.

Year Ended December 31, 2013 vs. December 31, 2012

EQT Midstream s operating income totaled $328.8 million for 2013 compared to $237.3 million for 2012. The increase in operating income was primarily the result of increased transmission and gathering net operating revenues and gains on dispositions, partly offset by increased operating expenses and a decrease in storage, marketing and other net operating revenues.

The $96.1 million increase in total net operating revenues was due to a $56.1 million increase in transmission net operating revenues and $49.2 million increase in gathering net operating revenues, partially offset by a decrease in storage, marketing and other net operating revenues.

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Transmission net operating revenues increased from the prior year primarily as a result of $44.0 million of additional firm capacity reservation revenues and usage charges, $10.1 million of fees associated with transported volumes in excess of firm capacity and increased pipeline safety revenues.

Gathering net operating revenues increased due to a 39% increase in gathered volumes, partly offset by a 17% decrease in the average gathering fee. The gathered volume increase was driven by higher volumes gathered for EQT Production in the Marcellus play. The average gathering fee decreased due to the mix of gathered volumes as Marcellus volumes increased while Huron and other volumes, which have a higher gathering fee, decreased.

Storage, marketing and other net operating revenues decreased from the prior year primarily as a result of lower realized margins and reduced activity due to lower price spreads. In addition, revenues on NGLs marketed for non-affiliated producers decreased by $2.8 million primarily as a result of lower liquids pricing partially offset by slightly higher liquids volumes.

On December 31, 2013, the Company sold certain energy marketing contracts to a third party for $20.0 million. These contracts were natural gas sales agreements with approximately 1,000 end use customers with total volumes of approximately 12 Bcf in 2013. In conjunction with this transaction, the Company recognized a pre-tax gain of $19.6 million in 2013, which is included in gains on dispositions in the Statements of Consolidated Income.

Total operating revenues increased $108.5 million primarily as a result of the increase in gathered volumes and increased transmission revenue, partly offset by the lower gathering rate. Total purchased gas costs increased $12.4 million primarily as a result of an increase in commodity prices.

Operating expenses totaled $236.4 million for 2013 compared to $212.1 million for 2012. The increase in SG&A was primarily the result of increased personnel costs of $5.9 million including incentive compensation expenses, $2.2 million of increased overhead allocated from affiliates, a $2.1 million unfavorable change in bad debt expense primarily as a result of lower recoveries from the Lehman Brothers settlement in 2013 and $2.0 million of lower reserve reductions in 2013, primarily related to the expected recovery of a long-term, volume-based regulatory asset. DD&A increased as a result of additional assets placed in-service. Operating and maintenance (O&M) expenses were flat to the prior year as increases in personnel and other gathering and transmission business expenses in 2013 were offset by reduced compressor operating expenses.

Year Ended December 31, 2012 vs. December 31, 2011

EQT Midstream s operating income totaled $237.3 million for 2012 compared to $416.6 million for 2011. The decrease in operating income was primarily the result of the $202.9 million pre-tax gain on the sales of Langley and Big Sandy in 2011 and increased operating expenses in 2012 partly offset by an increase in 2012 net operating revenues.

Total net operating revenues were $449.4 million for 2012 compared to $404.6 million for 2011. The increase in total net operating revenues was due to a $52.6 million increase in gathering net operating revenues and a $14.1 million increase in transmission net operating revenues, partly offset by a $21.9 million decrease in storage, marketing and other net operating revenues.

Gathering net operating revenues increased due to a 30% increase in gathered volumes, partly offset by a 7% decrease in the average gathering fee. The gathered volume increase was driven by higher volumes gathered for EQT Production in the Marcellus play. The average gathering fee decreased due to the mix of gathered volumes as Marcellus volumes increased while Huron and other volumes, which have a higher gathering fee, decreased.

Transmission net operating revenues in 2012 increased from the prior year primarily as a result of $15.8 million of increased capacity reservation revenues resulting from the Sunrise Pipeline project and the Equitrans 2010 Marcellus expansion project and higher firm transportation activity from affiliated shippers due to increased Marcellus volumes. These revenues were negatively impacted year over year by the absence of $16.0 million of revenues recorded on Big Sandy in the first half of 2011.

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Storage, marketing and other net operating revenues decreased from the prior year primarily as a result of unrealized losses on derivatives and inventory, lower margins and activity due to lower price spreads and volatility, and a $4.3 million decrease in net operating revenue from NGLs marketed for non-affiliated producers primarily as a result of lower liquids pricing.

Total operating revenues decreased $19.8 million primarily as a result of lower sales prices on decreased commercial activity and a lower gathering rate partly offset by an increase in gathered volumes and increased transmission revenue. Total purchased gas costs decreased $64.7 million primarily as a result of lower commodity prices on decreased commercial activity.

Operating expenses totaled $212.1 million for 2012 compared to $190.9 million for 2011. The increase in O&M was primarily the result of a $13.3 million decrease in 2011 of non-income taxes largely as a result of favorable property tax settlements recorded in 2011 combined with increases in 2012 in line with the growth of the business. In addition, personnel cost increases in 2012 were partly offset by the absence of $2.8 million in operating costs for Langley and Big Sandy in 2011. SG&A was flat year over year as the EQT Midstream segment recovered approximately $2.9 million from the Lehman Brothers bankruptcy, reversed $2.5 million in reserves for the recovery of a long-term, volume-based regulatory asset and allocated $5.2 million more in expenses to affiliates, offsetting increases in personnel costs and $1.2 million of increased expenses related to the Partnership s IPO and subsequent operation as a public company. DD&A increased as a result of higher assets placed in service.

Other Income Statement Items

Other Income

	Years Ended December 31,		
	2013	2012	2011
		(Thousands)	
Other income	$ 9,242	$ 15,536	$ 33,276

Other income includes equity in earnings of nonconsolidated investments, primarily the Company s investments in Nora Gathering, LLC, of $7.6 million, $6.1 million and $7.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Other income for the year ended December 31, 2013 also included $1.2 million of AFUDC compared to $6.8 million of AFUDC in 2012, a $5.6 million decrease as a result of the Sunrise Pipeline being placed into service during the third quarter of 2012. The Company also recognized a gain on the sale of leases of $0.4 million in 2013 compared to a gain on the sale of leases of $2.0 million in 2012.

Other income for the year ended December 31, 2012 included $6.8 million of AFUDC compared to $3.8 million in 2011, a $3.0 million increase as a result of further construction on the Equitrans Sunrise Pipeline project, which was placed into service during 2012. Other income for the year ended December 31, 2011 also included a $10.1 million pre-tax gain on the ANPI transaction and an $8.5 million gain on sales of available-for-sale securities.

Interest Expense

	Years Ended December 31,		
	2013	2012	2011
		(Thousands)	
Interest expense	$ 142,688	$ 184,786	$ 136,328

Interest expense decreased $42.1 million in 2013 compared to 2012 as a result of a $23.3 million payment to settle a forward-starting interest rate swap recorded as expense in 2012 and the Company s repayment of $200 million of 5.15% senior notes that matured in the fourth quarter of 2012 and $23.2 million of debentures that matured in 2013. This decrease was also attributable to higher capitalized interest of $22.9 million on increased Marcellus well development in 2013 compared to $15.6 million in 2012.

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Interest expense increased $48.5 million from 2011 to 2012 as a result of additional expense from the Company s November 2011 issuance of $750 million 4.875% notes due in 2021 and the $23.3 million payment to settle a forward-starting interest rate swap in 2012. These increases were partially offset by higher capitalized interest on increased Marcellus well development and midstream pipeline construction in 2012.

During the third quarter of 2011, the Company entered into an interest rate hedge in anticipation of refinancing $200 million of long-term debt scheduled to mature in November 2012. Given the Company s strong liquidity position, the Company retired the debt using cash on hand and recognized a $23.3 million expense in the year ended December 31, 2012 to close the interest rate hedge.

Weighted average annual interest rates on the Company s long-term debt were 6.4% for 2013 and 2012 and 6.8% for 2011. The weighted average annual interest rate on the Company s short-term debt was 1.7% and 1.8% for 2013 and 2011, respectively. The Company had no short-term debt in 2012.

Income Taxes

	Years Ended December 31,		
	2013	2012	2011
	(Thousands)		
Income taxes	$ 175,186	$ 71,461	$ 238,537

Income tax expense increased by $103.7 million from 2012 to 2013 as a result of higher pre-tax income and an increase in the Company s effective income tax rate from 32.4% to 33.6%. The increase in the rate from 2012 to 2013 was primarily due to an increase in pre-tax book income on state tax paying entities as well as a shift in the Company s business to states with higher income tax rates partially offset by state tax benefits realized in 2013 related to the Sunrise Merger and the Equitable Gas Transaction. The effective tax rate was also favorably impacted by the Partnership ownership structure whereby the Company consolidates the pre-tax income related to the noncontrolling public limited partners share of partnership earnings but does not record an income tax provision with respect to the portion of the Partnership s earnings allocated to its noncontrolling public limited partners. Both items were higher in 2013 than they were in the prior year.

Income tax expense decreased by $167.1 million from 2011 to 2012 as a result of lower pre-tax income and a decrease in the Company s effective income tax rate from 36.2% to 32.4%. The decrease in the rate from 2011 to 2012 was primarily due to a reduction in pre-tax book income on state tax paying entities. The effective tax rate was also favorably impacted in 2012 by the Partnership ownership structure whereby the Company consolidates the pre-tax income related to the noncontrolling public limited partners share of partnership earnings but does not record an income tax provision with respect to the portion of the Partnership s earnings allocated to its noncontrolling public limited partners. Other rate reconciling items had a larger percentage impact on the effective tax rate in 2012 than 2011 due to significantly higher pre-tax income in 2011.

The Company was in a cumulative federal taxable income position for 2013 primarily as a result of the taxable gains generated from the Sunrise Merger and the Equitable Gas Transaction. The Company was in an overall federal tax net operating loss (NOL) position for 2012 and 2011. In 2013, the Company began to utilize the NOLs it generated in previous years. For federal income tax purposes, the Company deducts approximately 83% of drilling costs as intangible drilling costs (IDCs) in the year incurred. IDCs, however, are sometimes limited for purposes of the alternative minimum tax (AMT) and can result in the Company paying AMT even when utilizing a regular tax NOL. See Note 9 to the Consolidated Financial Statements for further discussion of the Company s income taxes.

Income from Discontinued Operations, Net of Tax

	Years Ended December 31,		
	2013	2012	2011
		(Thousands)	
Income from discontinued operations, net of tax	$ 91,843	$ 47,493	$ 60,187

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Income from discontinued operations, net of tax, was $91.8 million for the year ended December 31, 2013 compared to $47.5 million for the year ended December 31, 2012. The $44.3 million increase in 2013 compared to 2012 was primarily the result of a $43.8 million gain recognized on the Equitable Gas Transaction during 2013. Excluding the gain recognized on the Equitable Gas Transaction, results for discontinued operations were relatively unchanged from 2012 to 2013 as favorable adjustments for the completion of a regulatory gas cost audit and colder weather in 2013 were offset by reduced revenues as a result of competitive contract renewals and an increase in bad debt expense.

Income from discontinued operations, net of tax, was $47.5 million for the year ended December 31, 2012 compared to $60.2 million for the year ended December 31, 2011. The $12.7 million decrease between periods was primarily due to record warm weather during 2012.

Net Income Attributable to Noncontrolling Interests

	Years Ended December 31,		
	2013	2012	2011
		(Thousands)	
Net income attributable to noncontrolling interests	$ 47,243	$ 13,016	$

Net income attributable to noncontrolling interests of the Partnership was $47.2 million for the year ended December 31, 2013 compared to $13.0 million for the year ended December 31, 2012. The increase resulted from higher capacity reservation revenues on the Partnership, which completed its IPO in the third quarter of 2012, as well as increased noncontrolling interests in 2013. Noncontrolling interests in the Partnership increased from 40.6% to 55.4% during the year ended December 31, 2013 as a result of the underwritten public offering of additional common units representing limited partner interests in the Partnership in July 2013.

Outlook

The Company is committed to profitably developing its natural gas, NGL and oil reserves through environmentally responsible, cost-effective and technologically advanced horizontal drilling. The market price for natural gas can be volatile and these fluctuations can impact the Company s revenues, earnings and liquidity. The Company is unable to predict future movements in the market price for natural gas and therefore, cannot predict the ultimate impact of prices on its operations; however, the Company monitors the market for natural gas and adjusts its strategy and operations appropriately. Due to the increased supply of natural gas in the United States Northeast region, pricing relative to Henry Hub was negative during the second half of 2013. The Company expects this trend in basis to continue to be negative.

Total capital investment, excluding acquisitions, is expected to be approximately $2.5 billion in 2014. Capital spending for well development (primarily drilling) in 2014 is expected to be approximately $1.9 billion, to support the drilling of approximately 357 gross wells, including 186 Marcellus wells, 120 Huron wells, 30 Upper Devonian wells and 21 wells in the Utica Shale of Ohio. Estimated sales volumes are expected to be 460 480 Bcfe for an anticipated production sales volume growth of approximately 24% in 2014, while NGL volumes are expected to be 6,800 6,900 Mbbls. To support continued growth in production, the Company plans to invest approximately $610 million on midstream infrastructure in 2014, and expects to add approximately 440 MMcf per day of incremental gathering capacity and approximately 750 MMcf per day of transmission capacity. The 2014 capital spending plan is expected to be funded by cash on hand, cash flow generated from operations and proceeds from midstream asset sales (dropdowns) to the Partnership.

The Company continues to focus on creating and maximizing shareholder value through the implementation of a strategy that economically accelerates the monetization of its asset base and prudently pursues investment opportunities, all while maintaining a strong balance sheet with solid cash flow. While the tactics continue to evolve based on market conditions, the Company is considering arrangements, including asset sales and joint ventures, to monetize the value of certain mature assets for re-deployment into its highest value development opportunities.

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Capital Resources and Liquidity

The Company s primary sources of cash for 2013 were cash flows from operating activities, proceeds from the underwritten public offering of common units of the Partnership and proceeds received from the Equitable Gas Transaction. The Company s primary use of cash in 2013 was for capital expenditures.

Operating Activities

The Company s net cash provided by operating activities increased $391.9 million from $808.5 million in 2012 to $1,200.4 million in 2013. The increase in operating receipts was primarily the result of a 43% increase in natural gas volumes sold, increases in transmission pipeline throughput and gathered volumes and a $44.7 million decrease in interest payments, partially offset by a $136.1 million increase in income tax payments primarily due to taxes payable on the Sunrise Merger and Equitable Gas Transaction.

The Company s net cash provided by operating activities decreased $96.5 million from $905.0 million in 2011 to $808.5 million in 2012. The decline in operating receipts was a result of several factors, including a 20% decline in average effective sales prices of natural gas, higher cash payments for interest of $58.4 million, a decrease in dividends received from Nora Gathering, LLC of $10.8 million, record warm weather in 2012 and higher operating expenses. This decrease was partially offset by a 33% increase in natural gas volumes sold, a 30% increase in gathered volumes and a $19.6 million decrease in cash payments for income taxes.

Investing Activities

Cash flows used in investing activities totaled $1,037.3 million for 2013 as compared to $1,382.1 million for 2012. The $344.8 million decrease in cash flows used was attributable to the proceeds received from the Equitable Gas Transaction of $740.6 million and from the sale of certain energy marketing contracts of $23.0 million, partially offset by higher capital expenditures in 2013. As further described below, the Company increased cash capital expenditures from continuing operations by $406.0 million from 2012 to 2013.

Cash flows used in investing activities totaled $1,382.1 million for 2012 as compared to $614.1 million for 2011. The $768.1 million increase in cash flows used was attributable to reduced proceeds received from the sale of assets in 2012 compared to the $620 million proceeds received for the sales of Langley and Big Sandy and $29.9 million received for the sales of available-for-sale securities, all in 2011. Additionally, as described below, the Company increased cash capital expenditures from continuing operations by $125.5 million from 2011 to 2012.

Capital Expenditures for Continuing Operations

	2014 Forecast	**2013 Actual**	**2012 Actual**	**2011 Actual**

Well development (primarily drilling)	$	1,908 million	$	1,237 million	$	857 million	$	938 million
Property acquisitions *			$	186 million	$	135 million	$	150 million
Midstream infrastructure	$	610 million	$	369 million	$	376 million	$	243 million
Other corporate items	$	4 million	$	5 million	$	3 million	$	5 million
Total	$	2,522 million	$	1,797 million	$	1,371 million	$	1,336 million
Less: non-cash **			$	33 million	$	13 million	$	103 million
Total cash capital expenditures	$	2,522 million	$	1,764 million	$	1,358 million	$	1,233 million

* The Company does not forecast property acquisitions within its capital spending plan.

** The Company capitalizes certain labor overhead costs which include a portion of non-cash stock-based compensation expense. These non-cash capital expenditures in the table above were $33 million, $13 million and $10 million of stock-based compensation expense for the years ended 2013, 2012 and

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2011, respectively. Non-cash capital expenditures also included $93 million of liabilities assumed in exchange for producing properties in the ANPI transaction for the year ended 2011.

Capital expenditures for drilling and development totaled $1,237 million and $857 million during 2013 and 2012, respectively. The Company spud 225 gross wells (224 net wells) in 2013, including 168 horizontal Marcellus wells with approximately 830,000 feet of pay, 50 horizontal Huron wells with approximately 300,000 feet of pay and 7 horizontal Utica wells with approximately 42,000 feet of pay, compared to 135 gross wells (129 net wells) in 2012, including 127 horizontal Marcellus wells with approximately 700,000 feet of pay, 7 horizontal Huron wells with approximately 37,000 feet of pay and 1 horizontal Utica well with approximately 5,000 feet of pay. The $380 million increase in capital expenditures for well development was driven by an increase in completed feet of pay, an increase in completed frac stages and an increase in wells spud offset slightly by lower cost per foot primarily in the Marcellus play. Capital expenditures for 2013 also included $129 million for undeveloped property acquisitions, including $13 million within the Utica play and $116 million within the Marcellus play, and $57 million for the purchase of Marcellus wells acquired in the Chesapeake acquisition.

Capital expenditures for the midstream operations totaled $369 million for 2013. During the year, EQT Midstream turned in-line approximately 49 miles of pipeline and 2,100 horsepower of compression primarily in the Marcellus play. EQT Midstream also added 385 MMcf per day of incremental gathering capacity and 450 MMcf per day of incremental transmission capacity in 2013. During 2012, midstream capital expenditures were $376 million. EQT Midstream turned in-line 89 miles of pipeline and 36,000 horsepower of compression primarily within the Marcellus play.

Capital expenditures for drilling and development totaled $857 million and $938 million during 2012 and 2011, respectively. The Company spud 135 gross wells (129 net wells) in 2012, including 127 horizontal Marcellus wells with approximately 700,000 feet of pay, 7 horizontal Huron wells with approximately 37,000 feet of pay and 1 horizontal Utica well with approximately 5,000 feet of pay, compared to 222 gross wells (213 net wells) in 2011, including 105 horizontal Marcellus wells with approximately 500,000 feet of pay and 115 horizontal Huron wells with approximately 550,000 feet of pay. The $81 million decrease in capital expenditures for well development was primarily due to the suspension of drilling wells in the Huron play in 2012. This was partially offset by additional development of the Marcellus play at a lower average cost per well in 2012 when compared to 2011 as a result of drilling efficiencies and lower service company costs. Capital expenditures for 2012 also included approximately $135 million for undeveloped property acquisitions, including $78 million within the Utica play and $57 million within the Marcellus play.

Capital expenditures for the midstream operations totaled $376 million for 2012. During the year, EQT Midstream turned in-line approximately 89 miles of pipeline and 36,000 horsepower of compression primarily in the Marcellus play. EQT Midstream also added 455 MMcf per day of incremental gathering capacity and 700 MMcf per day of incremental transmission capacity in 2012. During 2011, midstream capital expenditures were $243 million. EQT Midstream turned in-line 46 miles of pipeline and 20,000 horsepower of compression primarily within the Marcellus play in 2011.

Financing Activities

Cash flows provided by financing activities totaled $500.5 million for 2013 as compared to cash flows used in financing activities of $75.5 million in 2012. In 2013, the Company received net proceeds of $529.4 million from the Partnership s underwritten public offering of common units, paid distributions to noncontrolling interests of $32.8 million, repaid maturing long-term debt of $23.2 million and received proceeds from employee compensation plan exercises of $45.1 million. In 2012, the Company received $276.8 million from the Partnership s IPO, repaid maturing long-term debt of $219.3 million, paid distributions to noncontrolling interests of $5.0 million and received proceeds from employee compensation plan exercises of $7.9 million.

In December 2012, in connection with its announcement of a definitive agreement to transfer Equitable Gas and Homeworks to PNG Companies, the Company reduced its annual dividend rate, effective January 2013, to $0.12 per share, which the Company believed better reflected the blend of the Company s core businesses remaining after the closing of the Equitable Gas Transaction a dividend supporting midstream business and a capital-intensive, rapidly growing production business. The $113.7 million favorable impact on cash provided

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by financing activities resulting from the decline in the dividend rate was partially offset by the $27.8 million increase in distributions to noncontrolling interests of the Partnership.

Cash flows used in financing activities totaled $75.5 million for 2012 as compared to cash flows provided by financing activities of $540.3 million in 2011. In 2012, the Company received $276.8 million in connection with the Partnership s IPO, repaid maturing long-term debt of $219.3 million and paid the initial distribution to the Partnership s noncontrolling interests of $5.0 million. In 2011, the Company issued $750 million of 4.875% Senior Notes due November 15, 2021 and repaid short-term loans of $53.7 million.

Short-term Borrowings

EQT primarily utilizes short-term borrowings to fund capital expenditures in excess of cash flow from operating activities until the expenditures can be permanently financed and to fund required margin deposits on derivative commodity instruments. Margin deposit requirements vary based on natural gas commodity prices, our credit ratings and the amount and type of derivative commodity instruments.

As of December 31, 2013, the Company had a $1.5 billion revolving credit facility that expires on December 8, 2016. The Company may request two one-year extensions of the expiration date, the approval of which is subject to satisfaction of certain conditions.

The revolving credit facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes. The credit facility is underwritten by a syndicate of 16 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company.

Under the terms of the revolving credit facility, the Company may obtain base rate loans or fixed period Eurodollar rate loans. Base rate loans are denominated in dollars and bear interest at a base rate plus a margin based on the Company s then current credit ratings. Fixed period Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the Company s then current credit ratings.

The Company had no loans or letters of credit outstanding under its revolving credit facility as of December 31, 2013 and 2012. For the years ended December 31, 2013 and 2012, the Company incurred commitment fees averaging approximately 24 basis points and 25 basis points, respectively, to maintain credit availability under the revolving credit facility.

The maximum amount of outstanding short-term loans at any time for the Company during the year ended December 31, 2013 was $178.5 million. The average daily balance of short-term loans outstanding for the Company during the year ended December 31, 2013 was approximately $12.1 million at a weighted average annual interest rate of 1.67%. The Company had no short-term loans outstanding at any time during the year ended December 31, 2012.

The Company s short-term borrowings generally have original maturities of three months or less.

In February 2014, the Company amended and restated its $1.5 billion revolving credit agreement. The amended and restated revolving credit agreement expires in February 2019. The other terms and conditions are substantially similar to the prior revolving credit agreement.

As of December 31, 2013, the Partnership had a $350 million revolving credit facility that expires on July 2, 2017. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. The credit facility is underwritten by a syndicate of 13 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Partnership. The Company is not a guarantor of the Partnership s obligations under the credit facility. The Partnership s obligations under the revolving portion of the credit facility are unsecured.

The Partnership, which was formed in 2012, had no letters of credit and no loans outstanding under the revolving credit facility at any time during the years ended December 31, 2013 and 2012. For the years ended

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December 31, 2013 and 2012, the Partnership incurred commitment fees averaging approximately 25 basis points to maintain credit availability under the revolving credit facility.

Under the terms of its revolving credit facility, the Partnership may obtain base rate loans or fixed period Eurodollar rate loans. Base rate loans are denominated in dollars and bear interest at a base rate plus a margin based on the Partnership s then current credit rating. Fixed period Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the Partnership s then current credit rating.

In February 2014, the Partnership amended and restated its revolving credit agreement by, among other things, increasing the size of the facility to $750 million and extending the term to February 2019.

Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at December 31, 2013. Changes in credit ratings may affect the Company s cost of short-term and long-term debt (including interest rates and fees under its lines of credit), collateral requirements under derivative instruments and access to the credit markets.

Rating Service	Senior Notes	Outlook
Moody s Investors Service	Baa3	Stable
Standard & Poor s Ratings Services	BBB	Stable
Fitch Ratings Service	BBB-	Stable

The Company s credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. The Company cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a credit rating agency if, in its judgment, circumstances so warrant. If the credit rating agencies downgrade the Company s ratings, particularly below investment grade, the Company s access to the capital markets may be limited, borrowing costs and margin deposits on derivative contracts would increase, counterparties may request additional assurances and the potential pool of investors and funding sources may decrease. The required margin on derivative instruments is also subject to significant change as a result of factors other than credit rating, such as gas prices and credit thresholds set forth in agreements between the hedging counterparties and the Company.

The Company s debt agreements and other financial obligations contain various provisions that, if not complied with, could result in termination of the agreements, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the debt agreements relate to maintenance of a debt-to-total capitalization ratio, limitations on transactions with affiliates, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company s credit facility contains financial covenants that require a total debt-to-total capitalization ratio of no greater than 65%. The calculation of this ratio excludes the effects of accumulated other comprehensive income (OCI). As of December 31, 2013, the Company was in compliance with all debt provisions and covenants.

The Partnership s credit facility contains various provisions that, if not complied with, could result in termination of the credit facility, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the credit facility relate to maintenance of permitted leverage coverage and interest coverage ratios, limitations on transactions with affiliates, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. Under the credit facility, the Partnership is required to maintain a consolidated leverage ratio of not more than 5.00 to 1.00 (or, after the Partnership obtains an investment grade rating, not more than 5.50 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and, until the Partnership obtains an investment grade rating, a consolidated interest coverage ratio of not less than 3.00 to 1.00. As of December 31, 2013, the Partnership was in compliance with all credit facility provisions and covenants.

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Commodity Risk Management

The substantial majority of the Company s commodity risk management program is related to hedging sales of the Company s produced natural gas. The Company s overall objective in this hedging program is to protect cash flow from undue exposure to the risk of changing commodity prices. The Company s risk management program may include the use of exchange-traded natural gas futures contracts and options and OTC natural gas swap agreements and options (collectively, derivative commodity instruments) to hedge exposures to fluctuations in natural gas prices. The derivative commodity instruments currently utilized by the Company are primarily NYMEX swaps, collars and futures. The Company also enters into fixed price natural gas sales agreements that are satisfied by physical delivery. The Company s fixed price natural gas sales agreements include contracts that fix only the NYMEX portion of the price and contracts that fix NYMEX and basis.

As of February 13, 2014, the approximate volumes and prices of the Company s hedge position for 2014 through 2016 production were:

	2014	2015	2016 (b)
NYMEX swaps and fixed price sales			
Total Volume (Bcf)	225	124	60
Average Price per Mcf (a)	$ 4.35	$ 4.39	$ 4.45
Collars			
Total Volume (Bcf)	24	23	_
Average Floor Price per Mcf (NYMEX) (a)	$ 5.05	$ 5.03	$ _
Average Cap Price per Mcf (NYMEX) (a)	$ 8.85	$ 8.97	$ _

(a) The average price is based on a conversion rate of 1.05 MMBtu/Mcf.

(b) For 2016, the Company executed a natural gas sales agreement for approximately 35 Bcf that includes a NYMEX ceiling price of $4.88 per Mcf.

See Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and Note 5 to the Company s Consolidated Financial Statements for further discussion of the Company s hedging program.

Other Items

Off-Balance Sheet Arrangements

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees were approximately $172 million as of December 31, 2013, extending at a decreasing amount for approximately 14 years.

In exchange for the Company s agreement to maintain these guarantee obligations, the purchaser of the NORESCO business and NORESCO agreed, among other things, that NORESCO would fully perform its obligations under each underlying agreement and agreed to reimburse the Company for any loss under the guarantee obligations, provided that the purchaser s reimbursement obligation will not exceed $6 million in the aggregate and will expire on November 18, 2014. In 2008, the original purchaser of NORESCO sold its interest in NORESCO and transferred its obligations to a third party. In connection with that event, the new owner delivered to the Company a $1 million letter of credit supporting its obligations.

The NORESCO guarantees are exempt from ASC Topic 460, Guarantees. The Company has determined that the likelihood it will be required to perform on these arrangements is remote and any potential payments are expected to be immaterial to the Company s financial position, results of operations and liquidity. As such, the Company has not recorded any liabilities in its Consolidated Balance Sheets related to these guarantees.

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Rate Regulation

As described under Regulation in Item 1, Business, the Company s transmission and storage operations and a portion of its gathering operations are subject to various forms of rate regulation. As described in Note 1 to the Consolidated Financial Statements, regulatory accounting allows the Company to defer expenses and income as regulatory assets and liabilities which reflect future collections or payments through the regulatory process. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of the deferred costs.

Schedule of Contractual Obligations

	Total	2014	2015-2016 (Thousands)	2017-2018	2019+
Purchase obligations	$ 2,167,779	$ 140,762	$ 377,214	$ 361,693	$ 1,288,110
Long-term debt	2,498,366	11,162	169,004	708,000	1,610,200
Interest payments	937,803	159,354	306,182	265,703	206,564
Operating leases	134,240	42,922	44,062	16,933	30,323
Pension and other post-retirement benefits	82,385	4,378	7,662	7,007	63,338
Total contractual obligations	$ 5,820,573	$ 358,578	$ 904,124	$ 1,359,336	$ 3,198,535

Purchase obligations are commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines, some of which extend up to approximately 15 years. The Company has entered into agreements to release some of its capacity to various third parties.

Operating leases are primarily entered into for various office locations and warehouse buildings, as well as dedicated drilling rigs in support of the Company s drilling program. The obligations for the Company s various office locations and warehouse buildings totaled approximately $63.9 million as of December 31, 2013. The Company has agreements with Savanna Drilling, LLC, Pioneer Drilling Company and Patterson Drilling Company to provide drilling equipment and services to the Company over the next three years. These obligations totaled approximately $70.4 million as of December 31, 2013.

As discussed in Note 9 to the Consolidated Financial Statements, the Company had a total reserve for unrecognized tax benefits at December 31, 2013 of $57.1 million, of which $9.8 million is offset against deferred tax assets since it would primarily reduce the related NOL carryover and research and experimentation tax credit carryforwards. The Company is currently unable to make reasonably reliable estimates of the period of cash settlement of these potential liabilities with taxing authorities; therefore, this amount has been excluded from the schedule of contractual obligations.

Commitments and Contingencies

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company accrues legal and other direct costs related to loss contingencies when actually incurred. The Company has established reserves it believes to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, the Company believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the Company s financial position, results of operations or liquidity.

See Note 18 to the Consolidated Financial Statements for further discussion of the Company s commitments and contingencies.

Critical Accounting Policies Involving Significant Estimates

The Company s significant accounting policies are described in Note 1 to the Consolidated Financial Statements. The discussion and analysis of the Consolidated Financial Statements and results of operations are based upon the Company s Consolidated Financial Statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these Consolidated Financial Statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. The following critical accounting policies, which were reviewed by the Company s Audit Committee, relate to the Company s more significant judgments and estimates used in the preparation of its Consolidated Financial Statements. Actual results could differ from those estimates.

Accounting for Oil and Gas Producing Activities: The Company uses the successful efforts method of accounting for its oil and gas production activities. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the property has proved reserves. If an exploratory well does not result in proved reserves, the costs of drilling the well are charged to expense and included within cash flows from investing activities in the Consolidated Statements of Cash Flows. The costs of development wells are capitalized whether productive or nonproductive. Depletion is calculated based on the annual actual production multiplied by the depletion rate per unit. The depletion rate is derived by dividing the total costs capitalized over the number of units expected to be produced over the life of the reserves.

The carrying values of the Company s proved oil and gas properties are reviewed for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. In order to determine whether impairment has occurred, the Company estimates the expected future cash flows (on an undiscounted basis) from its oil and gas properties and compares these estimates to the carrying values of the properties. The estimated future cash flows used to test those properties for recoverability are based on risk-adjusted proved and, in some cases, probable reserves, utilizing assumptions about the use of the asset, market prices for oil and gas and future operating costs. Proved oil and gas properties that have carrying amounts in excess of estimated future cash flows would be deemed unrecoverable. Those properties would be written down to fair value, which would be estimated by discounting the estimated future cash flows using discount rate assumptions that marketplace participants would use in their estimates of fair value.

Capitalized costs of unproved properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period in which that determination is made. Undeveloped properties had a net book value of $450.2 million and $385.6 million as of December 31, 2013 and 2012, respectively.

The Company believes that the accounting estimate related to the accounting for oil and gas producing activities is a critical accounting estimate because the Company must assess the remaining recoverable proved reserves, a process which can be significantly impacted by management s expectations regarding proved undeveloped drilling locations and its future development plans. Should the Company begin to develop new producing regions or begin more significant exploration activities, future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions.

Oil and Gas Reserves: Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10, are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The Company s estimates of proved reserves are made and reassessed annually using geological and reservoir data as well as production performance data. Reserve estimates are prepared and updated by the Company s engineers and audited by the Company s independent engineers. Revisions may result from changes in, among

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other things, reservoir performance, development plans, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits sooner. A material change in the estimated volumes of reserves could have an impact on the depletion rate calculation and the financial statements.

The Company estimates future net cash flows from natural gas and oil reserves based on selling prices and costs using a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation. Income tax expense is computed using expected future tax rates and giving effect to tax deductions and credits available under current laws and which relate to oil and gas producing activities.

The Company believes that the accounting estimate related to oil and gas reserves is a critical accounting estimate because the Company must periodically reevaluate proved reserves along with estimates of future production and the estimated timing of development expenditures. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions.

Income Taxes: The Company recognizes deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the Company s Consolidated Financial Statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial reporting and tax bases of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

The Company has recorded deferred tax assets principally resulting from federal and state NOL carryforwards, an alternative minimum tax credit carryforward, incentive compensation and deferred compensation plans and pension and other post-retirement benefits recorded in OCI. The Company has established a valuation allowance against a portion of the deferred tax assets related to the state NOL carryforwards, as it is believed that it is more likely than not that these deferred tax assets will not all be realized. No other significant valuation allowances have been established, as it is believed that future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize these deferred tax assets. Any determination to change the valuation allowance would impact the Company s income tax expense and net income in the period in which such a determination is made.

The Company estimates the amount of financial statement benefit to record for uncertain tax positions by first determining whether it is more likely than not that a tax position in a tax return will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If this step is satisfied, then the Company must measure the tax position. The tax position is measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. See Note 9 to the Company s Consolidated Financial Statements for further discussion.

The Company believes that accounting estimates related to income taxes are critical accounting estimates because the Company must assess the likelihood that deferred tax assets will be recovered from future taxable income and exercise judgment regarding the amount of financial statement benefit to record for uncertain tax positions. When evaluating whether or not a valuation allowance must be established on deferred tax assets, the Company exercises judgment in determining whether it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized. The Company considers all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed, including carrybacks, tax planning strategies, reversal of deferred tax assets and liabilities and forecasted future taxable income. In making the determination related to uncertain tax positions, the Company considers the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of financial statement benefit. To the extent that an uncertain tax position or valuation allowance is established or increased or decreased during a period, the Company must include an expense or benefit within tax expense in the income statement. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions.

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Derivative Instruments: The Company enters into derivative commodity instrument contracts primarily to mitigate exposure to commodity price risk associated with future natural gas production. The Company also enters into derivative instruments to hedge other forecasted natural gas purchases and sales and natural gas inventory, and a limited number of interest rate swaps and to hedge exposure to fluctuations in interest rates and basis swaps to protect from undue exposure to the risk of geographic disparities in commodity prices. Energy trading contracts are also utilized to leverage assets and limit exposure to shifts in market prices. Derivative instruments are required to be recorded on the balance sheet as either an asset or a liability measured at fair value. If the derivative qualifies and is designated for cash flow hedge accounting, the change in fair value of the derivative is recognized in accumulated OCI (a component of equity) to the extent that the hedge is effective and in the income statement to the extent it is ineffective. If the derivative is designated as a fair value hedge, does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. For fair value hedges, the Company also records the change in the fair value of the hedged item (inventory) in the Statements of Consolidated Income. The Company de-designated all derivative commodity instruments that were designated and qualified as fair value hedges effective October 1, 2013. See Commodity Risk Management above, Item 7A, Quantitative and Qualitative Disclosures About Market Risk and Note 5 to the Consolidated Financial Statements for additional information regarding hedging activities.

The Company estimates the fair value of all derivative instruments using quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use as inputs market-based parameters, including but not limited to forward curves, discount rates, broker quotes, volatilities and nonperformance risk. Nonperformance risk considers the effect of the Company s credit standing on the fair value of liabilities and the effect of the counterparty s credit standing on the fair value of assets. The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company s or counterparty s credit rating and the yield of a risk-free instrument and credit default swap rates where available. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond the Company s control.

A substantial majority of the Company s derivative financial instruments are designated as cash flow hedges. Should these instruments fail to meet the criteria for hedge accounting or be de-designated, the subsequent changes in fair value of the instruments would be recorded in earnings, which could materially impact the results of operations. One of the requirements for cash flow hedge accounting is that a derivative instrument be highly effective at offsetting the changes in cash flows of the transaction being hedged. Effectiveness may be impacted by various factors including changes in basis and counterparty credit ratings. Because most of the Company s derivative instruments hedge natural gas prices at NYMEX, but most of the Company s physical sales are at Appalachian Basin pricing, changes in basis may result in ineffectiveness of the instruments. Counterparty credit ratings may impact ineffectiveness as it must be probable that the counterparty will perform in order for the hedge to be effective. The Company monitors counterparty credit quality by reviewing counterparty credit fundamentals, credit ratings, credit default swap rates and market activity.

In addition, the derivative commodity instruments used to mitigate exposure to commodity price risk associated with future natural gas production may limit the benefit the Company would receive from increases in the prices for oil and natural gas and may expose the Company to margin requirements. Given the Company s price risk management position and price volatility, the Company may be required from time to time to deposit cash with or provide letters of credit to its counterparties in order to satisfy these margin requirements.

The Company believes that the accounting estimates related to derivative instruments are critical accounting estimates because the Company s financial condition, results of operations and liquidity can be significantly impacted by changes in the market value of the Company s derivative instruments due to the volatility of natural gas prices, both NYMEX and basis, by changes in the effectiveness of cash flow hedges due to changes in basis and estimates of non-performance risk and by changes in margin requirements. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions.

Contingencies and Asset Retirement Obligations: The Company is involved in various regulatory and legal proceedings that arise in the ordinary course of business. The Company records a liability for contingencies based upon its assessment that a loss is probable and the amount of the loss can be reasonably estimated. The Company

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considers many factors in making these assessments, including history and specifics of each matter. Estimates are developed in consultation with legal counsel and are based upon an analysis of potential results.

The Company also accrues a liability for legal asset retirement obligations based on an estimate of the timing and amount of their settlement. For oil and gas wells, the fair value of the Company s plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are spud. Upon initial recognition of an asset retirement obligation, the Company increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to depreciation, depletion and amortization, and the initial capitalized costs are depleted over the useful lives of the related assets.

The Company is required to operate and maintain its natural gas pipeline and storage systems, and intends to do so as long as supply and demand for natural gas exists, which the Company expects for the foreseeable future. Therefore, the Company believes that the substantial majority of its natural gas pipeline and storage system assets have indeterminate lives.

The Company believes that the accounting estimates related to contingencies and asset retirement obligations are critical accounting estimates because the Company must assess the probability of loss related to contingencies and the expected amount and timing of asset retirement obligations. In addition, the Company must determine the estimated present value of future liabilities. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions.

Share-Based Compensation: The Company awards share-based compensation in connection with specific programs established under the 1999 and 2009 Long-Term Incentive Plans. Awards to employees are typically made in the form of performance-based awards, time-based restricted stock and stock options. Awards to directors are typically made in the form of phantom units.

Performance-based awards expected to be satisfied in cash are treated as liability awards. Awards under the 2011 Value Driver Award Program, which were paid out in cash on December 31, 2012, were treated as liability awards. Phantom units (which vest upon grant) expected to be satisfied in cash are also treated as liability awards. For liability awards, the Company is required to estimate, on grant date and on each reporting date thereafter until vesting and payment, the fair value of the ultimate payout based upon the expected performance through, and value of the Company s common stock on, the vesting date. The Company then recognizes a proportionate amount of the expense for each period in the Company s financial statements over the vesting period of the award, in the case of a performance-based award, and until payment, in the case of phantom units. The Company reviews its assumptions regarding performance and common stock value on a quarterly basis and adjusts its accrual when changes in these assumptions result in a material change in the fair value of the ultimate payouts.

Performance-based awards expected to be satisfied in Company common stock or Partnership common units are treated as equity awards. Awards under the 2011 Volume and Efficiency Program, the 2012 Executive Performance Incentive Program, the 2012 Value Driver Award Program, the 2013 Executive Performance Incentive Program, the 2013 Value Driver Award Program and the EQM Total Return Program, which remained outstanding at December 31, 2013, are treated as equity awards. For equity awards, the Company is required to determine the grant date fair value of the awards, which is then recognized as expense in the Company s financial statements over the vesting period of the award. Determination of the grant date fair value of the awards requires judgments and estimates regarding, among other things, the appropriate methodologies to follow in valuing the awards and the related inputs required by those valuation methodologies. Most often, the Company is required to obtain a valuation based upon assumptions regarding risk-free rates of return, dividend or distribution yields, expected volatilities and the expected term of the award. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend or distribution yield is based on the historical dividend or distribution yield of the Company s common stock or the Partnership s common units, as applicable, and any changes expected thereto, and, where applicable, of the common stock of the peer group members at the time of grant. Expected volatilities are based on historical volatility of the Company s common stock or the Partnership s common units and, where applicable, the common stock of the peer group members at the time of grant. The expected term represents the period of time elapsing during the applicable performance period.

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For time-based restricted stock awards, the grant date fair value of the awards is recognized as expense in the Company s financial statements over the vesting period, historically three years. For phantom units (which vest on date of grant) expected to be satisfied in equity, the grant date fair value of the awards is recognized as an expense in the Company s financial statements in the year of grant. The grant date fair value, in both cases, is determined based upon the closing price of the Company s common stock on the date of the grant.

For non-qualified stock options, the grant date fair value is recognized as expense in the Company s financial statements over the vesting period, typically two years. The Company utilizes the Black-Scholes option pricing model to measure the fair value of stock options, which includes assumptions for a risk-free interest rate, dividend yield, volatility factor and expected term. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the dividend yield of the Company s common stock at the time of grant. The expected volatility is based on historical volatility of the Company s common stock at the time of grant. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience at the time of grant.

The Company believes that the accounting estimates related to share-based compensation are critical accounting estimates because they may change from period to period based on changes in assumptions about factors affecting the ultimate payout of awards, including the number of awards to ultimately vest and the market price and volatility of the Company s common stock. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions. See Note 16 to the Consolidated Financial Statements for additional information regarding the Company s share-based compensation.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Derivative Instruments

The Company s primary market risk exposure is the volatility of future prices for natural gas and NGLs, which can affect the operating results of the Company primarily at EQT Production and the storage, marketing and other activities at EQT Midstream. The Company s use of derivatives to reduce the effect of this volatility is described in Notes 1 and 5 to the Consolidated Financial Statements and under the caption Commodity Risk Management in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations . The Company uses derivative commodity instruments that are placed primarily with financial institutions, and the creditworthiness of these institutions is regularly monitored. The Company also enters into derivative instruments to hedge other forecasted natural gas purchases and sales, to hedge natural gas inventory and to hedge exposure to fluctuations in interest rates. The Company s use of derivative instruments is implemented under a set of policies approved by the Company s Corporate Risk Committee and reviewed by the Audit Committee of the Board of Directors.

Commodity Price Risk

For the derivative commodity instruments used to hedge the Company s forecasted production, the Company sets policy limits relative to the expected production and sales levels which are exposed to price risk. For the derivative commodity instruments used to hedge forecasted natural gas purchases and sales which are exposed to price risk and to hedge natural gas inventory which is exposed to changes in fair value, most of which are hedged at NYMEX natural gas prices, the Company sets limits related to acceptable exposure levels. The Company does not enter into natural gas derivative commodity instruments for trading purposes.

The financial instruments currently utilized by the Company are primarily fixed price futures contracts, swap agreements and collar agreements which may require payments to or receipt of payments from counterparties based on the differential between two prices for the commodity. The Company also considers other contractual agreements in implementing its commodity hedging strategy.

The Company monitors price and production levels on a continuous basis and makes adjustments to quantities hedged as warranted. The Company s overall objective in its hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices.

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With respect to the derivative commodity instruments held by the Company as of December 31, 2013 and 2012, the Company hedged portions of expected equity production, portions of forecasted purchases and sales and portions of natural gas inventory by utilizing futures contracts, swap agreements and collar agreements covering approximately 388 Bcf and 356 Bcf of natural gas, respectively. See the Commodity Risk Management section in the Capital Resources and Liquidity section of Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, for further discussion.

A hypothetical decrease of 10% in the market price of natural gas from the December 31, 2013 and 2012 levels would increase the fair value of natural gas derivative instruments by approximately $151.7 million and $131.0 million, respectively. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2013 and 2012 levels would decrease the fair value of natural gas derivative instruments by approximately $151.6 million and $130.2 million, respectively.

The Company determined the change in the fair value of the derivative commodity instruments using a method similar to its normal determination of fair value as described in Note 1 to the Consolidated Financial Statements. The Company assumed a 10% change in the price of natural gas from its levels at December 31, 2013 and December 31, 2012. The price change was then applied to the natural gas derivative commodity instruments recorded on the Company s Consolidated Balance Sheets, resulting in the change in fair value.

The above analysis of the derivative commodity instruments held by the Company does not include the offsetting impact that the same hypothetical price movement may have on the Company s physical sales of natural gas. The portfolio of derivative commodity instruments held to hedge the Company s forecasted production approximates a portion of the Company s expected physical sales of natural gas. Therefore, an adverse impact to the fair value of the portfolio of derivative commodity instruments held to hedge the Company s forecasted production associated with the hypothetical changes in commodity prices referenced above should be offset by a favorable impact on the Company s physical sales of natural gas, assuming the derivative commodity instruments are not closed out in advance of their expected term, the derivative commodity instruments continue to function effectively as hedges of the underlying risk, the anticipated transactions occur as expected and basis does not significantly change.

If the underlying physical transactions or positions are liquidated prior to the maturity of the derivative commodity instruments, a loss on the financial instruments may occur or the derivative commodity instruments might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first.

Interest Rate Risk

Changes in interest rates affect the amount of interest the Company and the Partnership earn on cash, cash equivalents and short-term investments and the interest rates the Company and the Partnership pay on borrowings under their respective revolving credit facilities. All of the Company s long-term borrowings are fixed rate and thus do not expose the Company to fluctuations in its results of operations or liquidity from changes in market interest rates. Changes in interest rates do affect the fair value of the Company s fixed rate debt. See Notes 11 and 12 to the Consolidated Financial Statements for further discussion of the Company s borrowings and Note 6 to the Consolidated Financial Statements for a discussion of fair value measurements, including the fair value of long-term debt.

Other Market Risks

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company believes that NYMEX-traded futures contracts have limited credit risk because CFTC regulations are in place to protect exchange participants, including the Company, from potential financial instability of the exchange members. The Company s OTC swap and collar derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those companies individually as well as that industry as a whole.

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The Company utilizes various processes and analyses to monitor and evaluate its credit risk exposures. These include closely monitoring current market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions with financial counterparties that are of investment grade or better, enters into netting agreements whenever possible and may obtain collateral or other security.

Approximately 79%, or $107.4 million, of the Company s OTC derivative contracts outstanding at December 31, 2013 had a positive fair value. Approximately 80%, or $303.0 million, of the Company s OTC derivative contracts at December 31, 2012 had a positive fair value.

As of December 31, 2013, the Company was not in default under any derivative contracts and had no knowledge of default by any counterparty to derivative contracts. The Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company s established fair value procedure. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

The Company is also exposed to the risk of nonperformance by credit customers on physical sales of natural gas. A significant amount of revenues and related accounts receivable from EQT Production are generated from the sale of produced natural gas, NGLs and crude oil to certain marketers, utility and industrial customers located mainly in the Appalachian Basin and a gas processor in Kentucky and West Virginia. Additionally, a significant amount of revenues and related accounts receivable from EQT Midstream are generated from the gathering of natural gas in Kentucky, Virginia, Pennsylvania and West Virginia.

As of December 31, 2013, the Company had a $1.5 billion revolving credit facility that expires on December 8, 2016. The credit facility is underwritten by a syndicate of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. As of December 31, 2013, the Company had no loans or letters of credit outstanding under the facility. No one lender of the large group of financial institutions in the syndicate holds more than 10% of the facility. The Company s large syndicate group and relatively low percentage of participation by each lender is expected to limit the Company s exposure to problems or consolidation in the banking industry.

As of December 31, 2013, the Partnership had a $350 million revolving credit facility that expires on July 2, 2017. The credit facility is underwritten by a syndicate of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Partnership. As of December 31, 2013, the Partnership had no loans and letters of credit outstanding under the credit facility. No one lender of the large group of financial institutions in the syndicate holds more than 10% of the facility. The Partnership s large syndicate group and relatively low percentage of participation by each lender is expected to limit the Partnership s exposure to problems or consolidation in the banking industry.

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Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

EQT Corporation

We have audited the accompanying consolidated balance sheets of EQT Corporation and Subsidiaries as of December 31, 2013 and 2012, and the related statements of consolidated income, comprehensive income, stockholders equity and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EQT Corporation and Subsidiaries at December 31, 2013 and 2012, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EQT Corporation and Subsidiaries internal control over financial reporting as of December 31, 2013 based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 20, 2014 expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 20, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

EQT Corporation

We have audited EQT Corporation and Subsidiaries internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). EQT Corporation and Subsidiaries management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

In our opinion, EQT Corporation and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of EQT Corporation and Subsidiaries as of December 31, 2013 and 2012, and the related statements of consolidated income, comprehensive income, stockholders equity and cash flows for each of the three years in the period ended December 31, 2013 and our report dated February 20, 2014 expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 20, 2014

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EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME

YEARS ENDED DECEMBER 31,

	2013	2012	2011
	(Thousands except per share amounts)		
Operating revenues	$ 1,862,011	$ 1,377,222	$ 1,323,829
Operating expenses:			
Purchased gas costs	148,708	134,951	127,903
Operation and maintenance	97,762	99,257	84,348
Production	108,091	96,155	80,911
Exploration	18,483	10,370	4,932
Selling, general and administrative	200,849	172,243	153,624
Depreciation, depletion and amortization	653,132	474,617	313,868
Total operating expenses	1,227,025	987,593	765,586
Gain on dispositions	19,618		202,928
Operating income	654,604	389,629	761,171
Other income	9,242	15,536	33,276
Interest expense	142,688	184,786	136,328
Income before income taxes	521,158	220,379	658,119
Income taxes	175,186	71,461	238,537
Income from continuing operations	345,972	148,918	419,582
Income from discontinued operations, net of tax	91,843	47,493	60,187
Net income	437,815	196,411	479,769
Less: Net income attributable to noncontrolling interests	47,243	13,016	
Net income attributable to EQT Corporation	$ 390,572	$ 183,395	$ 479,769
Amounts attributable to EQT Corporation:			
Income from continuing operations	$ 298,729	$ 135,902	$ 419,582
Income from discontinued operations	91,843	47,493	60,187
Net income	$ 390,572	$ 183,395	$ 479,769
Earnings per share of common stock attributable to EQT Corporation:			
Basic:			
Income from continuing operations	$ 1.98	$ 0.91	$ 2.81
Income from discontinued operations	0.61	0.32	0.40
Net income	$ 2.59	$ 1.23	$ 3.21
Diluted:			
Income from continuing operations	$ 1.97	$ 0.90	$ 2.79
Income from discontinued operations	0.60	0.32	0.40
Net income	$ 2.57	$ 1.22	$ 3.19

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

YEARS ENDED DECEMBER 31,

	2013	2012 (Thousands)	2011
Net income	$ 437,815	$ 196,411	$ 479,769
Other comprehensive (loss) income, net of tax:			
Net change in cash flow hedges:			
Natural gas, net of tax (benefit) expense of ($50,200), ($61,757) and $110,186	(76,489)	(93,878)	166,840
Interest rate, net of tax expense (benefit) of $63, $4,833 and ($5,720)	144	6,369	(7,433)
Unrealized loss on available-for-sale securities			(4,896)
Pension and other post-retirement benefits liability adjustment, net of tax expense (benefit) of $16,115, ($1,992) and ($2,752)	21,501	(1,085)	(4,474)
Other comprehensive (loss) income	(54,844)	(88,594)	150,037
Comprehensive income	382,971	107,817	629,806
Less: Comprehensive income attributable to noncontrolling interests	47,243	13,016	
Comprehensive income attributable to EQT Corporation	$ 335,728	$ 94,801	$ 629,806

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

YEARS ENDED DECEMBER 31,

	2013	2012 (Thousands)	2011
Cash flows from operating activities:			
Net income	$ 437,815	$ 196,411	$ 479,769
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income taxes	110,363	95,185	234,019
Depreciation, depletion and amortization	676,570	499,118	339,297
Gain on dispositions	(185,894)		(202,928)
Provisions for (recoveries of) losses on accounts receivable	2,957	(1,235)	1,581
Other income	(9,508)	(15,965)	(34,138)
Stock-based compensation expense	52,618	40,230	20,080
Unrealized losses (gains) on derivatives and inventory	15,601	7,182	(1,497)
Lease impairment	14,198	5,543	2,587
Noncash financial instrument put premium		8,227	
Changes in other assets and liabilities:			
Dividend from Nora Gathering, LLC	9,000	12,750	23,500
Accounts receivable and unbilled revenues	(44,818)	(48,364)	14,317
Inventory	30,090	43,277	1,117
Prepaid expenses and other	(8,248)	(17,404)	22,812
Accounts payable	53,527	32,275	42,262
Other items, net	46,127	(48,757)	(37,758)
Net cash provided by operating activities	1,200,398	808,473	905,020
Cash flows from investing activities:			
Capital expenditures from continuing operations	(1,764,262)	(1,358,246)	(1,232,723)
Capital expenditures from discontinued operations	(36,637)	(28,745)	(31,313)
Proceeds from sale of assets	740,587	4,842	619,999
Proceeds from sale of energy marketing contracts	23,000		
Proceeds from sale of available-for-sale securities			29,947
Net cash used in investing activities	(1,037,312)	(1,382,149)	(614,090)
Cash flows from financing activities:			
Proceeds from the issuance of common units of EQT Midstream Partners, LP, net of issuance costs	529,442	276,780	
Dividends paid	(18,094)	(131,803)	(131,625)
Distributions to noncontrolling interests	(32,781)	(5,031)	
Repayments and retirements of long-term debt	(23,204)	(219,315)	(15,457)
Proceeds and tax benefits from exercises under employee compensation plans	45,137	7,871	2,791
Proceeds from issuance of long-term debt			750,000
Debt issuance costs and revolving credit facility origination fees		(4,022)	(11,738)
Decrease in short-term loans			(53,650)
Net cash provided by (used in) financing activities	500,500	(75,520)	540,321
Net change in cash and cash equivalents	663,586	(649,196)	831,251
Cash and cash equivalents at beginning of year	182,055	831,251	
Cash and cash equivalents at end of year	$ 845,641	$ 182,055	$ 831,251
Cash paid during the year for:			
Interest, net of amount capitalized	$ 143,187	$ 187,884	$ 129,486
Income taxes, net	$ 163,703	$ 27,605	$ 47,242

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2013	2012
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 845,641	$ 182,055
Accounts receivable (less accumulated provision for doubtful accounts: $5,171 in 2013; $5,883 in 2012)	235,781	190,258
Inventory	19,656	45,165
Derivative instruments, at fair value	107,647	304,237
Prepaid expenses and other	46,700	38,451
Assets of discontinued operations		92,678
Total current assets	1,255,425	852,844
Equity in nonconsolidated investments	128,983	130,368
Property, plant and equipment	11,062,136	9,153,207
Less: accumulated depreciation and depletion	2,728,374	2,093,795
Net property, plant and equipment	8,333,762	7,059,412
Other assets	73,883	57,182
Noncurrent assets of discontinued operations		750,056
Total assets	$ 9,792,053	$ 8,849,862

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2013	2012
	(Thousands)	
Liabilities and Stockholders Equity		
Current liabilities:		
Current portion of long-term debt	$ 11,162	$ 23,204
Accounts payable	330,329	276,802
Derivative instruments, at fair value	29,651	75,562
Other current liabilities	152,268	146,605
Liabilities of discontinued operations		48,291
Total current liabilities	523,410	570,464
Long-term debt	2,490,354	2,502,969
Deferred income taxes	1,655,765	1,442,071
Other liabilities and credits	258,396	187,941
Noncurrent liabilities of discontinued operations		257,615
Total liabilities	4,927,925	4,961,060
Equity:		
Stockholders equity		
Common stock, no par value, authorized 320,000 shares, shares issued: 175,684 in 2013 and 2012	1,869,843	1,770,545
Treasury stock, shares at cost: 24,800 in 2013 and 25,575 in 2012	(447,738)	(461,774)
Retained earnings	2,567,980	2,195,502
Accumulated other comprehensive income	44,703	99,547
Total common stockholders equity	4,034,788	3,603,820
Noncontrolling interests in consolidated subsidiaries	829,340	284,982
Total equity	4,864,128	3,888,802
Total liabilities and equity	$ 9,792,053	$ 8,849,862

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED EQUITY

YEARS ENDED DECEMBER 31, 2013, 2012 and 2011

	Common Stock					
	Shares Outstanding	No Par Value	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests in Consolidated Subsidiaries	Total Equity
			(Thousands)			
Balance, December 31, 2010	149,153	$ 1,244,826	$ 1,795,766	$ 38,104		$ 3,078,696
Comprehensive income (net of tax):						
Net income			479,769			479,769
Net change in cash flow hedges:						
Natural gas, net of tax of $110,186				166,840		166,840
Interest rate, net of tax of ($5,720)				(7,433)		(7,433)
Unrealized gain on available-for-sale securities				(4,896)		(4,896)
Pension and other post-retirement benefits liability adjustment, net of tax of ($2,752)				(4,474)		(4,474)
Dividends ($0.88 per share)			(131,625)			(131,625)
Stock-based compensation plans, net	324	16,953				16,953
Balance, December 31, 2011	149,477	$ 1,261,779	$ 2,143,910	$ 188,141		$ 3,593,830
Comprehensive income (net of tax):						
Net income			183,395		13,016	196,411
Net change in cash flow hedges:						
Natural gas, net of tax of ($61,757)				(93,878)		(93,878)
Interest rate, net of tax of $4,833				6,369		6,369
Pension and other post-retirement benefits liability adjustment, net of tax of ($1,992)				(1,085)		(1,085)
Dividends ($0.88 per share)			(131,803)			(131,803)
Stock-based compensation plans, net	632	41,621			217	41,838
Distributions to noncontrolling interests ($0.35 per common unit)					(5,031)	(5,031)
Issuance of common units of EQT Midstream Partners, LP					276,780	276,780
Deferred taxes related to IPO of EQT Midstream Partners, LP		5,371				5,371
Balance, December 31, 2012	150,109	$ 1,308,771	$ 2,195,502	$ 99,547	$ 284,982	$ 3,888,802
Comprehensive income (net of tax):						
Net income			390,572		47,243	437,815
Net change in cash flow hedges:						
Natural gas, net of tax of ($50,200)				(76,489)		(76,489)
Interest rate, net of tax of $63				144		144
Pension and other post-retirement benefits liability adjustment, net of tax of $16,115				21,501		21,501
Dividends ($0.12 per share)			(18,094)			(18,094)
Stock-based compensation plans, net	775	114,975			454	115,429
Distributions to noncontrolling interests ($1.55 per common unit)					(32,781)	(32,781)

Issuance of common units of EQT Midstream Partners, LP					529,442	529,442
Deferred taxes related to the public offering of common units of EQT Midstream Partners, LP		(1,641)				(1,641)
Balance, December 31, 2013	150,884	$ 1,422,105	$ 2,567,980	$ 44,703	$ 829,340	$ 4,864,128

Common shares authorized: 320,000 shares. Preferred shares authorized: 3,000 shares. There are no preferred shares issued or outstanding.

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013

1. Summary of Significant Accounting Policies

Principles of Consolidation: The Consolidated Financial Statements include the accounts of EQT Corporation and all subsidiaries, ventures and partnerships in which a controlling interest is held (EQT or the Company). All significant intercompany accounts and transactions have been eliminated in consolidation. EQT owns a 2.0% general partner interest, all incentive distribution rights and a 42.6% limited partner interest in EQT Midstream Partners, LP (the Partnership) (NYSE: EQM). The Partnership is consolidated in EQT s consolidated financial statements. EQT records the noncontrolling interest of the public limited partners in EQT s financial statements. The Company utilizes the equity method of accounting for companies where its ownership is less than or equal to 50% and significant influence exists.

Segments: Operating segments are revenue-producing components of the enterprise for which separate financial information is produced internally and which are subject to evaluation by the Company s chief operating decision maker in deciding how to allocate resources.

The Company reports its operations in two segments, which reflect its lines of business. The EQT Production segment includes the Company s exploration for, and development and production of, natural gas, natural gas liquids (NGLs) and a limited amount of crude oil in the Appalachian Basin. EQT Midstream s operations include the natural gas gathering, transportation, storage and marketing activities of the Company, including ownership and operation of the Partnership.

Substantially all of the Company s operating revenues, income from operations and assets are generated or located in the United States.

Reclassification: Certain previously reported amounts have been reclassified to conform to the current year presentation. Additionally, financial statements and notes to the financial statements previously reported in prior periods have been recast to reflect the presentation of discontinued operations as a result of the Equitable Gas Transaction. Refer to Note 2 for additional information on discontinued operations.

Use of Estimates: The preparation of financial statements in conformity with United States generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and accompanying notes. Actual results could differ from those estimates.

Cash Equivalents: The Company considers all highly liquid investments with an original maturity of three months or less when purchased to be cash equivalents. These investments are accounted for at cost. Interest earned on cash equivalents is included as a reduction of interest expense.

Inventories: Generally, the Company s inventory balance consists of natural gas stored underground or in pipelines and materials and supplies recorded at the lower of average cost or market. For hedged inventory subject to fair value hedges, the Company adjusts the average cost for the change in natural gas spot prices from the date the inventory is hedged until settlement. These fair value adjustments become part of the average cost of the inventory. During the years ended December 31, 2013, 2012 and 2011, the Company recorded losses for lower of cost or market adjustments of $0.4 million, $7.0 million and $7.2 million, respectively, which became part of the average cost of the inventory.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

Property, Plant and Equipment: The Company s property, plant and equipment consist of the following:

	As of December 31, 2013	As of December 31, 2012
	(Thousands)	
Oil and gas producing properties, successful efforts method	$ 8,152,951	$ 6,750,343
Accumulated depletion	(2,134,953)	(1,572,775)
Net oil and gas producing properties	6,017,998	5,177,568
Midstream plant	2,807,165	2,308,362
Accumulated depreciation and amortization	(547,991)	(483,358)
Net midstream plant	2,259,174	1,825,004
Other properties, at cost less accumulated depreciation	56,590	56,840
Net property, plant and equipment	$ 8,333,762	$ 7,059,412

Oil and gas producing properties use the successful efforts method of accounting for production activities. Under this method, the cost of productive wells, including mineral interests, wells and related equipment, development dry holes, as well as productive acreage, are capitalized and depleted using the unit-of-production method. These capitalized costs include salaries, benefits and other internal costs directly attributable to these activities. The Company capitalized internal costs of $93.5 million, $72.1 million and $69.3 million in 2013, 2012 and 2011, respectively. The Company capitalized $22.9 million, $15.6 million and $13.3 million of interest relative to Marcellus well development in 2013, 2012 and 2011, respectively. Depletion expense is calculated based on the actual production multiplied by the applicable depletion rate per unit. The depletion rates are derived by dividing the costs capitalized by the number of units expected to be produced over the life of the reserves for lease costs and well costs separately. Costs of exploratory dry holes, geological and geophysical activities, delay rentals and other property carrying costs are charged to expense. The majority of the Company s oil and gas producing properties consist of gas producing properties which were depleted at an overall average rate of $1.50 per Mcfe, $1.52 per Mcfe and $1.25 per Mcfe produced for the years ended December 31, 2013, 2012 and 2011, respectively.

The carrying values of the Company s proved oil and gas properties are reviewed for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. In order to determine whether impairment has occurred, the Company estimates the expected future cash flows (on an undiscounted basis) from its oil and gas properties and compares these estimates to the carrying values of the properties. The estimated future cash flows used to test those properties for recoverability are based on risk-adjusted proved and, in some cases, probable reserves, utilizing assumptions about the use of the asset, market prices for oil and gas and future operating costs. Proved oil and gas properties that have carrying amounts in excess of estimated future cash flows would be deemed to be unrecoverable. Those properties would be written down to fair value, which would be estimated by discounting the estimated future cash flows using discount rate assumptions that marketplace participants would use in their estimates of fair value. For the years ended December 31, 2013, 2012 and 2011, the Company did not recognize impairment charges on developed oil and gas properties.

Capitalized costs of unproved properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period in which that determination is made. Undeveloped properties had a net book value of $450.2 million and $385.6 million at December 31, 2013 and 2012, respectively. Undeveloped property impairments primarily as a result of lease expirations prior to drilling of $14.2 million, $5.5 million and $2.6 million are included in exploration expense for the years ended December 31, 2013, 2012 and 2011, respectively.

At December 31, 2013 and 2012, the Company had no capitalized exploratory well costs.

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Midstream property, plant and equipment is carried at cost. Depreciation is calculated using the straight-line method based on estimated service lives. Midstream property consists largely of gathering and transmission systems (25-60 year estimated service life), buildings (35 year estimated service life), office equipment (3-7 year estimated service life), vehicles (5 year estimated service life), and computer and telecommunications equipment and systems (3-7 year estimated service life).

Major maintenance projects that do not increase the overall life of the related assets are expensed. When major maintenance materially increases the life or value of the underlying asset, the cost is capitalized.

Sales and Retirements Policies: No gain or loss is recognized on the partial sale of proved developed oil and gas reserves unless non-recognition would significantly alter the relationship between capitalized costs and remaining proved reserves for the affected amortization base. When gain or loss is not recognized, the amortization base is reduced by the amount of the proceeds.

Regulatory Accounting: EQT Midstream s regulated operations consist of interstate pipeline operations subject to regulation by the Federal Energy Regulatory Commission (FERC) and certain FERC-regulated gathering operations. The application of regulatory accounting allows the Company to defer expenses and income on its Consolidated Balance Sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the Statements of Consolidated Income for a non-regulated company. The deferred regulatory assets and liabilities are then recognized in the Statements of Consolidated Income in the period in which the same amounts are reflected in rates.

The following table presents the total regulated net revenues and operating expenses included in the operations of EQT Midstream:

	Years Ended December 31,		
	2013	**2012**	**2011**
		(Thousands)	
Midstream revenues	$ 184,767	$ 131,184	$ 113,774
Midstream operating expenses	$ 71,517	$ 66,202	$ 76,247

The following table presents the regulated net property, plant and equipment included in EQT Midstream:

As of December 31,

		2013		2012
		(Thousands)		
Property, plant & equipment	$	1,015,118	$	797,405
Accumulated depreciation and amortization		(158,533)		(143,714)
Net property, plant & equipment	$	856,585	$	653,691

The regulatory assets associated with deferred taxes of $13.3 million and $18.3 million as of December 31, 2013 and 2012, respectively, are included in other assets in the Consolidated Balance Sheets and primarily represent deferred income taxes recoverable through future rates related to a historical deferred tax position and the equity component of allowance for funds used during construction (AFUDC). The Company expects to recover the amortization of the deferred tax position ratably over the corresponding life of the underlying assets that created the difference.

Derivative Instruments: Derivatives are held as part of a formally documented risk management program. The Company s risk management activities are subject to the management, direction and control of the Company s Corporate Risk Committee (CRC). The CRC reports to the Audit Committee of the Board of Directors and is composed of the president and chief executive officer, the chief financial officer and other officers and employees.

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The Company s risk management program includes the consideration and, when appropriate, the use of (i) exchange-traded natural gas futures contracts and options and over the counter (OTC) natural gas swap agreements and options (collectively, derivative commodity instruments) to hedge exposures to fluctuations in natural gas prices and (ii) interest rate swap agreements to hedge exposures to fluctuations in interest rates. The Company does not enter into derivative instruments for trading purposes.

The accounting for the changes in fair value of the Company s derivative instruments depends on the use of the derivative instruments. To the extent that a derivative instrument has been designated and qualifies as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of accumulated other comprehensive income (OCI), net of tax, and is subsequently reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The Company assesses the effectiveness of hedging relationships, as determined by the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, both at the inception of the hedge and on an on-going basis. If the gain (loss) for the hedging instrument is greater than the loss (gain) on the hedged item, the ineffective portion of the cash flow hedge is immediately recognized in operating revenues in the Statements of Consolidated Income.

For a derivative instrument that has been designated and qualifies as a fair value hedge, the change in the fair value for the instrument is recognized as a portion of operating revenues in the Statements of Consolidated Income each period. In addition, the change in the fair value of the hedged item (natural gas inventory) is recognized as a portion of operating revenues in the Statements of Consolidated Income. The Company elected to exclude the spot/forward differential from the assessment of effectiveness of the fair value hedges. Effective October 1, 2013, the Company de-designated all derivative commodity instruments that were previously designated and qualified as fair value hedges.

Any changes in fair value of derivative instruments that have not been designated as hedges are recognized in the Statements of Consolidated Income each period.

If a cash flow hedge is terminated or de-designated as a hedge before the settlement date of the hedged item, the amount of accumulated OCI recorded up to that date remains accrued, provided that the forecasted transaction remains probable of occurring. Subsequent changes in fair value of a de-designated derivative instrument are recorded in earnings. The amount recorded in accumulated OCI is primarily related to instruments which are currently designated as cash flow hedges.

The Company reports all gains and losses on its energy trading contracts net as operating revenues on its Statements of Consolidated Income.

Allowance for Funds Used During Construction: Carrying costs for the construction of certain long-term assets are capitalized by the Company and amortized over the related assets estimated useful lives. The capitalized amount for construction of regulated assets includes interest cost and a designated cost of equity for financing the construction of these assets which are subject to regulation by the FERC.

The debt portion of AFUDC is calculated based on the average cost of debt and is included as a reduction of interest expense in the Statements of Consolidated Income. AFUDC interest costs capitalized were $4.3 million, $3.9 million and $2.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The equity portion of AFUDC is calculated using the most recent equity rate of return approved by the applicable regulator. Equity amounts capitalized are included in other income in the Statements of Consolidated Income. The AFUDC equity amounts capitalized were $1.2 million, $6.8 million and $3.8 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Impairment of Long-Lived Assets: When events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable, the Company reviews its long-lived assets for impairment by first comparing the carrying value of the assets to the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the assets. If the carrying value exceeds the sum of the assets undiscounted cash

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flows, the Company records an impairment loss equal to the difference between the carrying value and fair value of the assets.

Other Current Liabilities: Other current liabilities as of December 31, 2013 and 2012 are detailed below.

	December 31, 2013	December 31, 2012
	(Thousands)	
Incentive compensation	$ 65,053	$ 52,291
Taxes other than income	39,073	37,048
Accrued interest payable	29,379	29,878
All other accrued liabilities	18,763	27,388
Total other current liabilities	$ 152,268	$ 146,605

Revenue Recognition: Revenue is recognized for production and gathering activities when deliveries of natural gas, NGLs and crude oil are made. Revenues from natural gas transportation and storage activities are recognized in the period the service is provided. Reservation revenues on firm contracted capacity are recognized over the contract period based on the contracted volume regardless of the amount of natural gas that is transported. The Company reports revenue from all energy trading contracts net in the income statement, regardless of whether the contracts are physically or financially settled. Contracts which result in physical delivery of a commodity expected to be used or sold by the Company in the normal course of business are considered normal purchases and sales and are not subject to derivative accounting. Revenues from these contracts are recognized at contract value when delivered. Revenues associated with energy trading contracts that do not result in physical delivery of an energy commodity are classified as derivative instruments. The Company accounts for gas-balancing arrangements under the entitlement method. The Company uses the gross method to account for overhead cost reimbursements from joint operating partners. During periods in which rates are subject to refund as a result of a pending rate case, the Company records revenue at the rates which are pending approval but reserves these revenues to the level of previously approved rates until the final settlement of the rate case.

Investments: EQT owns a 2.0% general partner interest, all incentive distribution rights and a 42.6% limited partner interest in the Partnership. The Partnership is consolidated in EQT s consolidated financial statements because EQT controls the Partnership through its ownership of the general partner. EQT records the noncontrolling interest of the public limited partners in EQT s financial statements. Investments in companies in which the Company has the ability to exert significant influence over operating and financial policies (generally 20% to 50% ownership) are accounted for using the equity method. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. These investments are classified as equity in nonconsolidated investments on the Consolidated Balance Sheets. The Company recognizes a loss in the value of an equity method investment that is other than a temporary decline. The Company analyzes its equity method investments based on its share of estimated future cash flows from the investment to determine whether the carrying amount will be recoverable.

Purchased Gas Costs: Purchased gas costs in the Statements of Consolidated Income include natural gas wellhead purchases, natural gas field line purchases, natural gas transmission line purchases, purchased gas cost adjustments, natural gas withdrawn from storage, gas used for product extraction and other gas supply expenses, including pipeline demand charges and transportation costs.

Income Taxes: The Company files a consolidated federal income tax return and utilizes the asset and liability method to account for income taxes. The provision for income taxes represents amounts paid or estimated to be payable, net of amounts refunded or estimated to be refunded, for the current year and the change in deferred taxes, exclusive of amounts recorded in OCI. Any refinements to prior years taxes made due to subsequent information are reflected as adjustments in the current period. Separate income taxes are calculated for income from continuing operations, income from discontinued operations and items charged or credited directly to stockholders equity.

Deferred income tax assets and liabilities are determined based on temporary differences between the financial reporting and tax bases of assets and liabilities and are recognized using enacted tax rates for the effect of

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such temporary differences. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

In accounting for uncertainty in income taxes of a tax position taken or expected to be taken in a tax return, the Company utilizes a recognition threshold and measurement attribute for the financial statement recognition and measurement. The recognition threshold requires the Company to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position in order to record any financial statement benefit. If it is more likely than not that a tax position will be sustained, then the Company must measure the tax position to determine the amount of benefit to recognize in financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income tax expense.

Provision for Doubtful Accounts: Judgment is required to assess the ultimate realization of the Company s accounts receivable, including assessing the probability of collection and the credit worthiness of certain customers. Reserves for uncollectible accounts are recorded as part of selling, general and administrative expense on the Statements of Consolidated Income. The reserves are based on historical experience, current and expected economic trends and specific information about customer accounts. Accordingly, actual results may differ from these estimates under different assumptions or conditions.

Earnings Per Share (EPS): Basic EPS are computed by dividing net income attributable to EQT Corporation by the weighted average number of common shares outstanding during the period, without considering any dilutive items. Diluted EPS are computed by dividing net income attributable to EQT Corporation by the weighted average number of common shares and potentially dilutive securities, net of shares assumed to be repurchased using the treasury stock method. Purchases of treasury shares are calculated using the average share price for the Company s common stock during the period. Potentially dilutive securities arise from the assumed conversion of outstanding stock options and other share-based awards. See Note 15.

Asset Retirement Obligations: The Company accrues a liability for legal asset retirement obligations based on an estimate of the timing and amount of settlement. For oil and gas wells, the fair value of the Company s plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are spud. Upon initial recognition of an asset retirement obligation, the Company increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to depreciation, depletion and amortization, and the initial capitalized costs are depleted over the useful lives of the related assets.

The Company is required to operate and maintain its natural gas pipeline and storage systems, and intends to do so as long as supply and demand for natural gas exists, which the Company expects for the foreseeable future. Therefore, the Company believes that the substantial majority of its natural gas pipeline and storage system assets have indeterminate lives.

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The following table presents a reconciliation of the beginning and ending carrying amounts of the Company s asset retirement obligations which are included in other liabilities and credits in the Consolidated Balance Sheets. The Company does not have any assets that are legally restricted for purposes of settling these obligations.

	Years Ended December 31,			
	2013			2012
	(Thousands)			
[redacted]				
Asset retirement obligation as of end of period	$	116,045	$	109,034

Self-Insurance: The Company is self-insured for certain losses related to workers compensation and maintains a self-insured retention for general liability, automobile liability, environmental liability and other casualty coverage. The Company maintains stop loss coverage with third-party insurers to limit the total exposure for general liability, automobile liability, environmental liability and workers compensation. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The estimated liabilities are based on analyses of historical data and actuarial estimates and are not discounted. The liabilities are reviewed by management quarterly and by independent actuaries annually to ensure that they are appropriate. While the Company believes these estimates are reasonable based on the information available, financial results could be impacted if actual trends, including the severity or frequency of claims, differ from estimates.

Accumulated other comprehensive income: The components of accumulated OCI, net of tax, are as follows:

	As of December 31,			
	2013			2012
	(Thousands)			
Net unrealized gain from natural gas hedging transactions	$	61,699	$	138,188
Net unrealized loss from interest rate swaps		(1,132)		(1,276)
Pension and other post-retirement benefits liability adjustment		(15,864)		(37,365)
Accumulated OCI	$	44,703	$	99,547

Noncontrolling interest: Noncontrolling interests represent third-party equity ownership in the Partnership and are presented as a component of equity in the Consolidated Balance Sheets. In the Statements of Consolidated Income, noncontrolling interests reflect the allocation of earnings to third-party investors, which for the Partnership gives effect to the incentive distribution rights declared for each period. See Note 3 for further discussion of noncontrolling interests related to the Partnership.

Subsequent Events: The Company has evaluated subsequent events through the date of the financial statement issuance.

2. Discontinued Operations

On December 17, 2013, the Company and its wholly-owned subsidiary Distribution Holdco, LLC (Holdco) completed the previously announced transactions contemplated by the Master Purchase Agreement, dated as of December 19, 2012 (as amended, the Master Purchase Agreement), by and among the Company, Holdco and PNG Companies LLC (PNG Companies), and the Asset Exchange Agreement, dated as of December 19, 2012 (as amended, the Asset Exchange Agreement), by and between the Company and PNG Companies. PNG Companies is the parent company of Peoples Natural Gas Company LLC. Pursuant to the Master Purchase Agreement and the Asset Exchange Agreement, the Company and Holdco transferred 100% of their ownership interests in Equitable Gas Company, LLC (Equitable Gas) and Equitable Homeworks, LLC (Homeworks) to PNG Companies (the Equitable Gas Transaction).

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Equitable Gas and Homeworks comprised substantially all of the Company s previously reported Distribution segment. The financial information of Equitable Gas and Homeworks is reflected as discontinued operations for all periods presented in these financial statements. Prior periods have been recast to reflect this presentation.

As consideration for the Equitable Gas Transaction, the Company received a $740.6 million cash payment, which is subject to certain post-closing adjustments, midstream assets with a preliminary estimated fair value of approximately $141.4 million and other contractual assets with a preliminary estimated fair value of $32.5 million. The contractual assets acquired included a lease of certain physical assets for which the Company will receive $2.5 million per year for 20 years. This lease is a capital lease under United States GAAP; therefore, the Company recorded a lease receivable, net of unearned interest, of $19.7 million as of December 31, 2013. Other contractual agreements resulted in intangible assets at the close of the transaction of $12.8 million. This balance included certain energy marketing contracts valued at $5.0 million which were sold on December 31, 2013 for this amount. The remaining contract-based intangible will be amortized over a 5 year period.

The Company recognized a gain on the sale of $43.8 million, subject to customary post-closing adjustments. The gain is net of tax expense of $122.5 million and is included in income from discontinued operations, net of tax, in the Statements of Consolidated Income.

The following table summarizes the components of discontinued operations activity:

	Years Ended December 31,		
	2013	**2012**	**2011**
		(Thousands)	
Operating revenues	$ 332,947	$ 314,821	$ 420,563
Income from discontinued operations before income taxes	251,378	81,328	101,010
Income taxes	159,535	33,835	40,823
Income from discontinued operations, net of tax	$ 91,843	$ 47,493	$ 60,187

The Company incurred $8.1 million and $4.5 million of transaction costs related to the Equitable Gas Transaction for the years ended December 31, 2013 and 2012, respectively, which costs are included in the results of discontinued operations for those periods. The Company also recognized a $51.6 million write off of income tax related regulatory assets (net of related deferred taxes) through income tax expense in discontinued operations in 2013.

As part of the Equitable Gas Transaction, the Company entered into certain commercial arrangements with PNG Companies and its affiliates that will result in the continuation of transmission and storage service activities between Equitable Gas and Equitrans, L.P. (Equitrans, a subsidiary of the Partnership) for a period of 20 years. For the years ended December 31, 2013, 2012 and 2011, these intra-entity revenues were $37.6 million, $36.8 million and $37.9 million, respectively. The Company considered the significance of these amounts compared to total operating revenues of the disposed component and determined that they were not significant. These amounts are included in revenues for the EQT Midstream segment in continuing operations, and are an expense in arriving at the results of discontinued operations for the years ended December 31, 2013, 2012 and 2011. This presentation is consistent with how these contracts will be reflected in future periods.

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The following table discloses the major classes of assets and liabilities of discontinued operations included in the Consolidated Balance Sheet:

	As of December 31, 2012 (Thousands)	
Assets		
Accounts receivable and unbilled receivables	$	42,919
Inventory		31,622
Other current assets		18,137
Total current assets		92,678
Property, plant and equipment, net		655,886
Regulatory assets		93,599
Other assets		571
Total noncurrent assets		750,056
Assets of discontinued operations	$	842,734
Liabilities		
Accounts payable	$	12,230
Accrued customer credits		32,376
Other current liabilities		3,685
Total current liabilities		48,291
Deferred income taxes		223,959
Pension and other post-retirement benefits		27,985
Other liabilities		5,671
Total noncurrent liabilities		257,615
Liabilities of discontinued operations	$	305,906

3. EQT Midstream Partners, LP

On July 2, 2012, the Partnership, a subsidiary of the Company, completed an underwritten initial public offering (IPO) of 14,375,000 common units representing limited partner interests in the Partnership, which represented 40.6% of the Partnership s outstanding equity. The Company retained a 59.4% equity interest in the Partnership, including 2,964,718 common units, 17,339,718 subordinated units and a 2% general partner interest. Prior to the IPO, the Company contributed to the Partnership 100% of Equitrans. A wholly-owned subsidiary of the Company serves as the general partner of the Partnership, and the Company continues to operate the Equitrans business pursuant to the contractual arrangements described below. The Company continues to consolidate the results of the Partnership but records an income tax provision only as to its ownership percentage. The Company records the noncontrolling interest of the public limited partners in its financial statements.

Also, in connection with the closing of the IPO:

- The Partnership, its general partner and the Company entered into an Omnibus Agreement (Omnibus Agreement), pursuant to which, among other things, the Company agreed to provide the Partnership with general and administrative services and a license to use the name EQT and related marks in connection with the Partnership s business. The Omnibus Agreement also provides for certain indemnification and reimbursement obligations between the Company and the Partnership.

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- The Company s wholly-owned subsidiary, EQT Gathering, LLC (EQT Gathering), and the Partnership entered into an operation and management services agreement (Services Agreement), pursuant to which EQT Gathering provides the Partnership s pipelines and storage facilities with certain operational and management services. The Services Agreement also provides for certain indemnification and reimbursement obligations between the Partnership and EQT Gathering.

- The Partnership entered into a $350 million revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, and a syndicate of lenders. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. The Company is not a guarantor of the Partnership s obligations under the credit facility.

- As a result of the IPO, the Company reversed $5.4 million of net deferred tax liability related to temporary differences between book and tax basis that would no longer impact the Company.

- The Company and the Partnership granted certain EQT employees, including executive officers of the Company and the Partnership s general partner, performance awards representing 146,490 common units of the Partnership. The Company accounted for these awards as equity awards using the grant date fair value. Additionally, the Partnership s general partner granted each of its independent directors 4,780 phantom units of the Partnership, which units vested upon grant. The value of the phantom units will be paid in common units of the Partnership on the earlier of the director s death or retirement from the general partner s Board of Directors. The Company accounts for these awards as equity awards and, as such, recorded compensation expense for the fair value of the awards at the grant date fair value.

The Partnership received cash proceeds, net of issuance costs, of approximately $277 million upon the closing of the IPO, which increased the noncontrolling interest component of total equity. Approximately $231 million of the proceeds were distributed to the Company, $12 million was retained by the Partnership to replenish amounts distributed by Equitrans to the Company prior to the IPO, $32 million was retained by the Partnership to pre-fund certain maintenance capital expenditures and $2 million was used by the Partnership to pay credit facility origination fees associated with the credit agreement entered into by the Partnership at the closing of the IPO.

On July 22, 2013, Sunrise Pipeline, LLC (Sunrise), a subsidiary of the Company, merged with and into Equitrans, a subsidiary of the Partnership, with Equitrans continuing as the surviving company (the Sunrise Merger). Sunrise continues to be consolidated by the Company as it is still under common control.

On July 22, 2013, the Partnership completed an underwritten public offering of 12,650,000 common units representing Partnership limited partner interests. Following the offering and the closing of the Sunrise Merger, the Company retained a 44.6% equity interest in the Partnership, which includes 3,443,902 common units, 17,339,718 subordinated units and a 2% general partner interest. The Partnership received net proceeds of $529.4 million from the offering, after deducting the underwriters discount and offering expenses of $20.9 million.

Net income attributable to noncontrolling interests (i.e. the limited partner units not owned by the Company) was $47.2 million and $13.0 million for the years ended December 31, 2013 and 2012, respectively. The Partnership paid distributions of $32.8 million ($1.55 per common unit) and $5.0 million ($0.35 per common unit) to noncontrolling interests for the years ended December 31, 2013 and 2012, respectively.

4. Financial Information by Business Segment

Operating segments are evaluated on their contribution to the Company s consolidated results based on operating income. Other income, interest and income taxes are managed on a consolidated basis. Headquarters costs are billed to the operating segments based upon an allocation of the headquarters annual operating budget. Differences between budget and actual headquarters expenses are not allocated to the operating segments. As part of the 2012 budgeting process, the Company allocated additional corporate overhead charges to the operating segments.

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The Company s management reviews and reports the EQT Production segment results with third-party transportation costs reflected as a deduction from operating revenues. Third-party transportation costs are recorded as a portion of purchased gas costs in the Consolidated Statements of Income.

	Years Ended December 31, 2013	2012	2011
		(Thousands)	
Revenues from external customers:			
EQT Production	$ 1,168,657	$ 793,773	$ 791,285
EQT Midstream	614,042	505,498	525,345
Third-party transportation costs (a)	142,281	126,783	87,034
Less intersegment revenues, net (b)	(62,969)	(48,832)	(79,835)
Total	$ 1,862,011	$ 1,377,222	$ 1,323,829
Operating income:			
EQT Production	$ 371,245	$ 187,913	$ 387,098
EQT Midstream (c)	328,782	237,324	416,611
Unallocated expenses (d)	(45,423)	(35,608)	(42,538)
Total operating income	$ 654,604	$ 389,629	$ 761,171
Reconciliation of operating income to income from continuing operations:			
Other income	$ 9,242	$ 15,536	$ 33,276
Interest expense	142,688	184,786	136,328
Income taxes	175,186	71,461	238,537
Income from continuing operations	$ 345,972	$ 148,918	$ 419,582

	As of December 31, 2013	2012
	(Thousands)	
Segment assets:		
EQT Production	$ 6,359,065	$ 5,675,534
EQT Midstream	2,514,429	2,046,558
Total operating segments	8,873,494	7,722,092
Headquarters assets, including cash and short-term investments	918,559	1,127,770
Total assets	$ 9,792,053	$ 8,849,862

EQT Production and EQT Midstream had segment assets of $5,256.6 million and $1,785.1 million, respectively, as of December 31, 2011.

(a) This amount reflects the reclassification of third-party transportation costs from operating revenues to purchased gas costs at the consolidated level.

(b) Includes entries to eliminate intercompany natural gas sales from EQT Production to EQT Midstream. The Company also had $37.6 million, $36.8 million and $37.9 million for the years ended December 31, 2013, 2012 and 2011, respectively, of intercompany eliminations for transmission and storage services between EQT Midstream and Distribution that have been recast to discontinued operations as a result of the Equitable Gas Transaction. Additionally, the Company had $2.6 million, $11.7 million and $64.5 million for the years ended December 31, 2013, 2012 and 2011, respectively, of intercompany eliminations for retail business activity between Distribution and EQT Midstream that have been recast to discontinued operations. These recast adjustments had no impact on the Company s net income for any period.

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(c) Gains on dispositions of $19.6 million and $202.9 million are included in EQT Midstream operating income for 2013 and 2011, respectively. See Note 7.

(d) Unallocated expenses consist primarily of incentive compensation, administrative costs and corporate overhead charges previously allocated to the Distribution segment that were reclassified to Headquarters as part of the recast of this Annual Report on Form 10-K to reflect the discontinued operations presentation requirements.

	Years Ended December 31,		
	2013	2012	2011
		(Thousands)	
Depreciation, depletion and amortization:			
EQT Production	$ 578,641	$ 409,628	$ 257,144
EQT Midstream	75,032	64,782	57,135
Other	(541)	207	(411)
Total	$ 653,132	$ 474,617	$ 313,868
Expenditures for segment assets:			
EQT Production (e)	$ 1,423,185	$ 991,775	$ 1,087,840
EQT Midstream	369,399	375,731	242,886
Other	4,292	3,134	4,855
Total	$ 1,796,876	$ 1,370,640	$ 1,335,581

(e) Expenditures for segment assets in the EQT Production segment include $186.2 million, $134.6 million and $57.2 million for property acquisitions in 2013, 2012 and 2011, respectively. Expenditures for segment assets in the EQT Production segment also include $92.6 million of liabilities assumed in exchange for producing properties as part of the ANPI transaction, as described in Note 8, in 2011.

5. Derivative Instruments

The Company s primary market risk exposure is the volatility of future prices for natural gas and NGLs, which can affect the operating results of the Company primarily at EQT Production and the storage, marketing and other activities at EQT Midstream. The Company s overall objective in its hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices.

The Company uses OTC derivative commodity instruments that are primarily placed with financial institutions, and the creditworthiness of these institutions is regularly monitored. The Company also uses exchange traded futures contracts that obligate the Company to buy or sell a designated commodity at a future date for a specified price and quantity at a specified location. Swap agreements involve payments to or receipts from counterparties based on the differential between two prices for the commodity. Collar agreements require the counterparty to pay the Company if the index price falls below the floor price and the Company to pay the counterparty if the index price rises above the cap price. The Company may also engage in a limited number of basis swaps to protect earnings from undue exposure to the risk of geographic disparities in commodity prices and interest rate swaps to hedge exposure to interest rate fluctuations on potential debt issuances.

The Company recognizes all derivative instruments as either assets or liabilities at fair value on a gross basis. These assets and liabilities are reported in the Consolidated Balance Sheets as derivative instruments at fair value. These derivative instruments are reported as either current assets or current liabilities due to their highly liquid nature. The Company can net settle its derivative instruments at any time.

The accounting for the changes in fair value of the Company s derivative instruments depends on the use of the derivative instruments. To the extent that a derivative instrument has been designated and qualifies as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component

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of accumulated OCI, net of tax, and is subsequently reclassified into the Statements of Consolidated Income in the same period or periods during which the forecasted transaction affects earnings. On December 31, 2013, the Company sold certain energy marketing contracts and de-designated related derivative instruments that were previously designated as cash flow hedges because it was probable that the forecasted transactions would not occur, resulting in a $1.0 million pre-tax gain in operating revenues within the Statements of Consolidated Income for the year ended December 31, 2013.

For a derivative instrument designated and qualified as a fair value hedge, the change in the fair value of the instrument was recognized as a portion of operating revenues in the Statements of Consolidated Income each period. In addition, the change in the fair value of the hedged item (natural gas inventory) is recognized as a portion of operating revenues in the Statements of Consolidated Income. The Company elected to exclude the spot/forward differential for the assessment of effectiveness of the fair value hedges.

Most of the derivative commodity instruments used by the Company to hedge its exposure to variability in expected future cash flows associated with the fluctuations in the price of natural gas related to the Company s forecasted sale of equity production and forecasted natural gas purchases and sales have been designated and qualify as cash flow hedges. Historically, some of the derivative commodity instruments used by the Company to hedge its exposure to adverse changes in the market price of natural gas stored in the ground were designated and qualified as fair value hedges. These positions were de-designated effective October 1, 2013. Any hedging ineffectiveness and any change in fair value of derivative instruments that have not been designated as hedges are recognized in the Statements of Consolidated Income each period.

The Company also enters into fixed price natural gas sales agreements that are satisfied by physical delivery. These physical commodity contracts qualify for the normal purchases and sales exception and are not subject to derivative instrument accounting.

Exchange-traded instruments are generally settled with offsetting positions. OTC arrangements require settlement in cash. Settlements of derivative commodity instruments are reported as a component of cash flows from operations in the accompanying Statements of Consolidated Cash Flows.

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	Years Ended December 31, 2013		2012 (Thousands)		2011	
Commodity derivatives designated as cash flow hedges						
Amount of gain recognized in OCI (effective portion), net of tax	$	10,669	$	86,259	$	239,019
Amount of gain reclassified from accumulated OCI, net of tax into operating revenues (effective portion)		87,158		180,137		72,179
Amount of (loss) recognized in operating revenues (ineffective portion) (a)		(21,335)		(75)		(181)
Interest rate derivatives designated as cash flow hedges						
Amount of (loss) recognized in OCI (effective portion), net of tax	$		$	(7,138)	$	(7,573)
Amount of (loss) reclassified from accumulated OCI, net of tax, into interest expense due to forecasted transactions no longer being probable				(13,266)		
Amount of (loss) reclassified from accumulated OCI, net of tax, into interest expense (effective portion)		(144)		(241)		(140)
Commodity derivatives designated as fair value hedges (b)						
Amount of (loss) gain recognized in operating revenues for fair value commodity contracts	$	(1,341)	$	3,878	$	12,263
Fair value gain (loss) recognized in operating revenues for inventory designated as hedged item		386		3,292		(6,059)
Derivatives not designated as hedging instruments						
Amount of gain recognized in operating revenues	$	2,834	$	2,176	$	4,209

(a) No amounts have been excluded from effectiveness testing of cash flow hedges.

(b) For the year ended December 31, 2013, the net impact on operating revenues consisted of a $0.5 million gain due to the exclusion of the spot/forward differential from the assessment of effectiveness and a $1.5 million loss due to changes in basis. For the year ended December 31, 2012, the net impact on operating revenues consisted of a $7.6 million gain due to the exclusion of the spot/forward differential from the assessment of effectiveness and a $0.4 million loss due to changes in basis. For the year ended December 31, 2011, the net impact on operating revenues consisted of a $7.6 million gain due to the exclusion of the spot/forward differential from the assessment of effectiveness and a $1.4 million loss due to changes in basis.

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	As of December 31, 2013 (Thousands)		As of December 31, 2012 (Thousands)	
Asset derivatives				
Commodity derivatives designated as hedging instruments	$	104,430	$	259,459
Commodity derivatives not designated as hedging instruments		3,217		44,778
Total asset derivatives	$	107,647	$	304,237
Liability derivatives				
Commodity derivatives designated as hedging instruments	$	27,618	$	27,946
Commodity derivatives not designated as hedging instruments		2,033		47,616
Total liability derivatives	$	29,651	$	75,562

During 2011, the Company entered into two forward-starting interest rate swaps to mitigate the risk of rising interest rates. As of December 31, 2011, one swap had settled and a related loss of $1.4 million, net of tax, was recorded in accumulated OCI, net of tax, to be recognized over the ten year term of the related debt issuance. The other interest rate swap was in a liability position at December 31, 2011, with $6.2 million included in accumulated OCI, net of tax, on that date. During 2012, the Company deferred an additional $7.1 million in accumulated OCI, net of tax, related to this forward-starting interest rate swap which settled in November 2012. As of December 31, 2012, the related forecasted debt issuance was no longer probable and the entire liability related to this swap of $23.3 million, pre-tax, was recognized in interest expense in the Statements of Consolidated Income. This resulted in the reversal of $13.3 million which had previously been deferred in accumulated OCI, net of tax. The forecasted debt issuance was no longer probable given the strong liquidity position at December 31, 2012.

The net fair value of derivative commodity instruments changed during 2013 primarily as a result of settlements and increased New York Mercantile Exchange (NYMEX) forward prices. The absolute quantities of the Company s derivative commodity instruments that have been designated and qualify as cash flow hedges totaled 398 Bcf and 365 Bcf as of December 31, 2013 and 2012, respectively, and are primarily related to natural gas swaps and collars. The open positions at December 31, 2013 had maturities extending through December 2017. The Company de-designated all derivative commodity instruments that were designated and qualified as fair value hedges effective October 1, 2013. The absolute quantities of the Company s derivative commodity instruments that were designated and qualified as fair value hedges totaled 8 Bcf as of December 31, 2012.

The Company deferred net gains of $61.7 million and $138.2 million in accumulated OCI, net of tax, as of December 31, 2013 and 2012, respectively, associated with the effective portion of the change in fair value of its derivative commodity instruments designated as cash flow hedges. Assuming no change in price or new transactions, the Company estimates that approximately $27.2 million of net unrealized gains on its derivative commodity instruments reflected in accumulated OCI, net of tax, as of December 31, 2013 will be recognized in earnings during the next twelve months due to the settlement of hedged transactions. During the year ended December 31, 2012, the Company identified an error related to the accounting for a derivative instrument put premium which should have been recognized over the period January 2010 through December 2011 in conjunction with the settlements of the related financial positions. The Company evaluated materiality in accordance with Securities and Exchange Commission (SEC) Staff Accounting Bulletins Topics 1.M and 1.N and considered relevant qualitative and quantitative factors. Based on this analysis, the Company corrected the error in the second quarter of 2012 through a reduction of EQT Production segment operating revenue by $8.2 million, an increase of accumulated OCI by $5.1 million and a decrease of deferred tax expense by $3.1 million. The Company concluded that this error was not material to any prior periods, the then expected annual results of 2012 or the trend in earnings over the affected periods. The error had no effect on cash flows or debt covenant compliance.

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company believes that NYMEX traded futures contracts have limited credit risk because Commodity Futures Trading Commission (CFTC) regulations are in place to protect exchange participants, including the Company, from potential financial instability of the exchange members. The Company s OTC swap and collar derivative instruments are primarily placed with financial institutions and thus are subject to events that would impact those companies individually as well as that industry as a whole.

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The Company utilizes various processes and analyses to monitor and evaluate its credit risk exposures. These include closely monitoring current market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions with financial counterparties that are of investment grade or better, enters into netting agreements whenever possible and may obtain collateral or other security.

When the net fair value of any of the Company s swap agreements represents a liability to the Company which is in excess of the agreed-upon threshold between the Company and the financial institution acting as counterparty, the counterparty requires the Company to remit funds to the counterparty as a margin deposit for the derivative liability which is in excess of the threshold amount. The Company records these deposits as a current asset. When the net fair value of any of the Company s swap agreements represents an asset to the Company which is in excess of the agreed-upon threshold between the Company and the financial institution acting as counterparty, the Company requires the counterparty to remit funds as margin deposits in an amount equal to the portion of the derivative asset which is in excess of the threshold amount. The Company records a current liability for such amounts received. The Company had no such deposits in its Consolidated Balance Sheets as of December 31, 2013 or December 31, 2012.

When the Company enters into exchange-traded natural gas contracts, exchanges may require the Company to remit funds to the corresponding broker as good-faith deposits to guard against the risks associated with changing market conditions. The Company must make such deposits based on an established initial margin requirement as well as the net liability position, if any, of the fair value of the associated contracts. The Company records these deposits as a current asset in the Consolidated Balance Sheets. In the case where the fair value of such contracts is in a net asset position, the broker may remit funds to the Company, in which case the Company records a current liability for such amounts received. The initial margin requirements are established by the exchanges based on the price, volatility and the time to expiration of the related contract. The margin requirements are subject to change at the exchanges discretion. The Company recorded current assets of $0.3 million and $0.7 million as of December 31, 2013 and December 31, 2012, respectively, for such deposits in its Consolidated Balance Sheets.

The Company recognizes all derivative instruments as either assets or liabilities at fair value on a gross basis. Margin deposits remitted to financial counterparties or received from financial counterparties related to OTC natural gas swap agreements and options and any funds remitted to or deposits received from the Company s brokers are recorded on a gross basis. The Company has netting agreements with financial institutions and its brokers that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities. The table below reflects the impact of netting agreements and margin deposits on gross derivative assets and liabilities as of December 31, 2013 and 2012.

As of December 31, 2013	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting agreements	Margin deposits remitted to counterparties	Derivative instruments, net
		(Thousands)		

Asset derivatives:								
Derivative instruments, at fair value	$	107,647	$	(20,843)	$		$	86,804
Liability derivatives:								
Derivative instruments, at fair value	$	29,651	$	(20,843)	$	(266)	$	8,542

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As of December 31, 2012	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting agreements	Margin deposits remitted to counterparties	Derivative instruments, net
		(Thousands)		
Asset derivatives:				
Derivative instruments, at fair value	$ 304,237	$ (73,753)	$	$ 230,484
Liability derivatives:				
Derivative instruments, at fair value	$ 75,562	$ (73,753)	$ (736)	$ 1,073

Certain of the Company s derivative instrument contracts provide that if the Company s credit ratings by Standard & Poor s Rating Services (S&P) or Moody s Investor Services (Moody s) are lowered below investment grade, additional collateral must be deposited with the counterparty. The additional collateral can be up to 100% of the derivative liability. As of December 31, 2013, the aggregate fair value of all derivative instruments with credit risk-related contingent features that were in a net liability position was $8.8 million, for which the Company had no collateral posted on December 31, 2013. If the Company s credit rating by S&P or Moody s had been downgraded below investment grade on December 31, 2013, the Company would not have been required to post additional collateral due to the agreements with the counterparties with which we had the liabilities as of December 31, 2013. Investment grade refers to the quality of the Company s credit as assessed by one or more credit rating agencies. The Company s senior unsecured debt was rated BBB by S&P and Baa3 by Moody s at December 31, 2013. In order to be considered investment grade, the Company must be rated BBB- or higher by S&P and Baa3 or higher by Moody s. Anything below these ratings is considered non-investment grade.

6. Fair Value Measurements

The Company records its financial instruments, principally derivative instruments, at fair value in its Consolidated Balance Sheets. The Company has an established process for determining fair value which is based on quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use as inputs market-based parameters, including but not limited to forward curves, discount rates, volatilities and nonperformance risk. Nonperformance risk considers the effect of the Company s credit standing on the fair value of liabilities and the effect of the counterparty s credit standing on the fair value of assets. The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company s or counterparty s credit rating and the yield of a risk-free instrument. The Company also considers credit default swaps rates where applicable.

The Company has categorized its assets and liabilities recorded at fair value into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities included in Level 1 include the Company s futures contracts. Assets and liabilities in Level 2 include the majority of the Company s swap agreements. As of December 31, 2012, assets and liabilities in Level 3 included the Company s collars and a limited number of the Company s swap agreements. As of December 31, 2013, the Company transferred $54.4 million of derivative instruments from Level 3 into Level 2.

The fair value of the assets and liabilities included in Level 2 is based on standard industry income approach models that use significant observable inputs, including NYMEX forward curves and LIBOR-based discount rates. The Company s collars are valued using standard industry income approach models and were historically classified in Level 3 because the volatility assumption in the option pricing model was not observable over the full duration of the collars. Effective December 31, 2013, the volatility assumption in the option pricing model is observable for the duration of the term of the collars outstanding. This change did not have a significant impact on the fair value of the

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derivative instruments previously included in Level 3. The significant observable inputs utilized by the option pricing model include NYMEX forward curves, natural gas volatilities and LIBOR-based discount rates.

The Company uses NYMEX forward curves to value futures, commodity swaps and collars. The NYMEX forward curves and LIBOR-based discount rates are validated to external sources at least monthly.

The following assets and liabilities were measured at fair value on a recurring basis during the applicable period:

		Fair value measurements at reporting date using		
Description	**December 31, 2013**	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
		(Thousands)		
Assets				
Derivative instruments, at fair value	$ 107,647	$ 240	$ 107,407	$
Liabilities				
Derivative instruments, at fair value	$ 29,651	$ 315	$ 29,336	$

		Fair value measurements at reporting date using		
Description	**December 31, 2012**	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
		(Thousands)		
Assets				
Derivative instruments, at fair value	$ 304,237	$ 1,228	$ 204,592	$ 98,417
Liabilities				

Derivative instruments, at fair value	$	75,562	$	1,609	$	66,250	$	7,703

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	Fair value measurements using significant unobservable inputs (Level 3) Derivative instruments, at fair value, net Years Ended December 31,			
	2013		2012	
	(Thousands)			
Balance at January 1	$	90,714	$	143,260
Total gains or losses:				
Included in earnings		640		(615)
Included in OCI		(2,554)		23,386
Purchases				(933)
Settlements		(34,381)		(74,384)
Transfers in and/or out of Level 3		(54,419)		
Balance at December 31	$		$	90,714

There were no material gains or losses included in earnings for the periods in the table above attributable to the changes in unrealized gains or losses relating to assets and liabilities held as of December 31, 2013 and 2012.

The carrying value of cash equivalents approximates fair value due to the short-term maturity of the instruments; these are considered Level 1 fair values.

The Company estimates the fair value of its debt using its established fair value methodology. Because not all of the Company s debt is actively traded, the fair value of the debt is a Level 2 fair value measurement. Fair value for non-traded debt obligations is estimated using a standard industry income approach model which utilizes a discount rate based on market rates for debt with similar remaining time to maturity and credit risk. The estimated fair value of long-term debt on the Consolidated Balance Sheets at December 31, 2013 and 2012 was approximately $2.8 billion and $2.9 billion, respectively.

As consideration for the Equitable Gas Transaction, the Company received midstream assets with a preliminary estimated fair value of approximately $141.4 million and other contractual assets with a preliminary estimated fair value of $32.5 million. These assets are Level 2 fair value measurements as they were valued using standard industry income approach models.

For information on the fair value of assets acquired in the Chesapeake acquisition and the fair value of assets related to the defined benefit pension plan assets, see Note 8 and Note 13, respectively.

7. Sales of Properties and Contracts

On December 17, 2013, the Company executed the Equitable Gas Transaction. Refer to Note 2 for additional information.

On December 31, 2013, the Company sold certain energy marketing contracts to a third party for $20.0 million. These contracts were natural gas sales agreements with approximately 1,000 customers with total volumes of approximately 12 Bcf in 2013. The Company received $18.0 million of cash on December 31, 2013; the remaining $2.0 million is expected to be collected in 2014. In conjunction with this transaction, the Company realized a pre-tax gain of $19.6 million in 2013.

Assets acquired as part of the Equitable Gas Transaction included energy marketing contracts with approximately 50 customers valued at $5.0 million. On December 31, 2013, the Company sold these contracts to a third party for $5.0 million, which was received on December 31, 2013.

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The Company received proceeds of $0.4 million and realized a pre-tax gain of $0.4 million in the year ended December 31, 2013 for the sale of approximately 128 gross acres in Westmoreland County, Pennsylvania. During the years ended December 31, 2012 and 2011, the Company sold leases relating to approximately 2,900 gross acres in Lycoming County, Pennsylvania. The Company received proceeds of $2.7 million and realized a pre-tax gain of $2.0 million in the year ended December 31, 2012. The Company received proceeds of $6.0 million and realized a pre-tax gain of $3.9 million in the year ended December 31, 2011. The gains on these dispositions are recorded in other income in the Statements of Consolidated Income.

On February 1, 2011, the Company sold its natural gas processing complex in Langley, Kentucky and the associated natural gas liquids pipeline (Langley) for $230 million. In conjunction with this transaction, the Company realized a pre-tax gain of $22.8 million.

On July 1, 2011, the Company sold the Big Sandy Pipeline (Big Sandy) for $390 million. Big Sandy is a natural gas pipeline regulated by the FERC. In conjunction with this transaction, the Company realized a pre-tax gain of $180.1 million.

8. Acquisitions

Chesapeake Energy Corporation Acreage

On June 3, 2013, the Company acquired approximately 99,000 net acres in southwestern Pennsylvania and ten horizontal Marcellus wells, located in Washington County, Pennsylvania, from Chesapeake Energy Corporation and its partners (Chesapeake) for approximately $114.2 million. The acreage includes 67,000 Marcellus acres, of which 42,000 acres are unlikely to be developed due to near-term lease expirations or a scattered footprint. Of the total purchase price, $57.2 million was allocated to the undeveloped acreage and $57.0 million was allocated to the acquired Marcellus wells. The Marcellus wells added approximately 1.7 Bcfe of production sales volumes in 2013 and represented approximately 53.5 Bcfe of proved developed reserves as of the acquisition date.

As the transaction qualified as a business combination under United States GAAP, the fair value of the acquired assets was determined using a market approach for the undeveloped acreage and a discounted cash flow model under the income approach for the wells. Significant unobservable inputs used in the analysis included the determination of estimated developed reserves and NYMEX forward pricing; as a result, valuation of the acquired assets is a Level 3 measurement.

Appalachian NPI, LLC

In December 2000, the Company sold a net profits interest (NPI) in certain producing properties located in the Appalachian Basin to a trust in exchange for approximately $298 million. The NPI entitled the trust to receive 100% of the net profits received from the sale of natural gas and oil from the producing properties until cumulative production from such properties reached a specified amount. The Company owned the Class B interest in the trust, entitling it to specified percentages of any available cash from the trust over time. An unrelated party, Appalachian NPI, LLC (ANPI), owned the Class A interest in the trust.

Effective May 4, 2011, the Company, through EQT Production Company, acquired the Class A interest in the trust thereby acquiring 100% of the NPI associated with the producing properties (the ANPI transaction). As part of the consideration for the acquired assets, the Company entered into a discounted natural gas sales agreement with ANPI and assumed a swap held by ANPI on the trust s sales of natural gas.

In addition, the Company assumed 7.76% Guaranteed Senior Notes due August 31, 2011 through February 28, 2016 in the aggregate principal amount of $57.1 million. At the time of the transaction, the notes had a fair value of $64.2 million.

Under United States GAAP, the ANPI transaction was a business combination achieved in stages because the Company owned an equity interest in the trust prior to the transaction. As required by the relevant accounting standard, the Company revalued its existing equity investment in the trust at fair value on the date of the acquisition and recorded a pre-tax gain of $10.1 million which is included in other income in the Statements of Consolidated

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Income. The fair value was determined using an internal model; significant inputs to the calculation included publicly available forward price curves, expected production volumes and operating costs, as well as Company-determined risk adjusted discount rates which were based on publicly available debt and equity risk premiums.

As a result of this transaction, the Company recorded an increase in oil and gas properties of $140.6 million resulting from the removal of the post-revaluation $48.0 million equity investment in the trust from its books and a net $92.6 million increase in liabilities consisting of: $64.2 million of long-term debt, a $16.4 million discounted sales agreement and a $12.7 million swap liability offset by various working capital balances.

9. Income Taxes

Income tax expense (benefit) from continuing operations is summarized as follows:

	Years Ended December 31, 2013	2012	2011
	(Thousands)		
Current:			
Federal	$ 100,796	$ 3,771	$ 30,837
State	46,758	229	1,434
Subtotal	147,554	4,000	32,271
Deferred:			
Federal	51,767	56,551	177,474
State	(23,940)	11,014	29,003
Subtotal	27,827	67,565	206,477
Amortization of deferred investment tax credit	(195)	(104)	(211)
Total income taxes	$ 175,186	$ 71,461	$ 238,537

The current income tax expense recorded in 2013 primarily related to federal alternative minimum tax (AMT) and state income taxes as a result of the tax gains generated from the Sunrise Merger as well as the Equitable Gas Transaction. The current income tax expense recorded in 2012 primarily related to AMT as a result of the tax gain generated from the proceeds received relating to the Partnership s IPO. The current tax expense recorded in 2011 primarily related to AMT and state taxes due as a result of the Company s sales of Langley and Big Sandy.

The American Taxpayer Relief Act of 2012 was enacted on January 2, 2013 and retroactively extended the research and experimentation (R&E) tax credit (with modifications) for 2012 and 2013 and extended 50% bonus depreciation for property placed in service after December 31, 2012 and before January 1, 2014.

On July 9, 2013, Pennsylvania House Bill 465 was signed into law by the Governor of the Commonwealth of Pennsylvania (the Commonwealth). This legislation adopted multiple changes to the Commonwealth s tax code, including an intangible expense addback provision effective in 2015, an increase of the cap on the net operating loss (NOL) deduction in 2014 and 2015 and an extension of the franchise tax through 2015. The impact of this law change has been reflected in the Company s financial statements.

In September 2013, the United States Treasury Department issued final regulations regarding the deduction and capitalization of expenditures related to tangible property and proposed regulations addressing the disposition of tangible property. These regulations do not address the tax treatment for network assets such as natural gas pipelines, do replace previously issued temporary regulations and are effective for tax years beginning January 1, 2014 with optional adoption in 2013. The Company elected not to adopt the regulations in 2013, but performed an analysis of the regulations and does not believe that they will have a material impact on its financial statements.

The Company utilized NOLs for federal tax purposes in 2013, given the aforementioned increase in current taxable income. The Company generated NOLs for federal tax purposes from 2009 to 2012, primarily as a result of intangible drilling costs (IDCs), which are deducted for tax purposes but capitalized for financial statement purposes, and from accelerated and bonus tax depreciation associated with the expansion of the Company s midstream business. For federal income tax purposes, the Company deducts approximately 83% of drilling costs as IDCs in the year incurred which typically will cause the Company to generate a tax loss for the year. The Company

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expects to continue to generate tax losses over the next several years as it continues its drilling program in Appalachia, excluding taxable gains which may be recorded from potential future asset sales. IDCs, however, are sometimes limited for AMT purposes which can result in the Company paying AMT despite the fact that taxable income has been fully offset by current tax deductions or NOL carryforwards.

Income tax expense differs from amounts computed at the federal statutory rate of 35% on pre-tax income as follows:

	Years Ended December 31,		
	2013	2012	2011
		(Thousands)	
Tax at statutory rate	$ 182,406	$ 77,133	$ 230,342
State income taxes	16,180	2,869	18,150
Federal tax credits and incentives	(750)	(439)	(660)
Permanent basis differences	(407)	(2,789)	(2,020)
Noncontrolling partners share of Partnership earnings	(16,535)	(4,571)	
Other	(5,708)	(742)	(7,275)
Income tax expense	$ 175,186	$ 71,461	$ 238,537
Effective tax rate	33.6%	32.4%	36.2%

The Company s effective tax rate for the year ended December 31, 2013 was 33.6% compared to 32.4% for the year ended December 31, 2012. The increase in the rate from 2012 to 2013 was primarily due to an increase in pre-tax book income on state tax paying entities as well as a shift in the Company s business to states with higher income tax rates. This was partially offset by state tax benefits of $9.8 million realized in 2013 primarily related to the Sunrise Merger and the Equitable Gas Transaction which allowed the Company to utilize NOLs that had previously been fully reserved. The overall rate was reduced in both periods as a result of the Company consolidating 100% of the pre-tax income related to the noncontrolling public limited partners share of partnership earnings but does not record an income tax provision with respect to the portion of the Partnership s earnings allocated to its noncontrolling public limited partners.

The Company s effective tax rate for the year ended December 31, 2012 was 32.4% compared to 36.2% for the year ended December 31, 2011. The decrease in the rate from 2011 to 2012 was primarily due to a reduction in pre-tax book income on state tax paying entities and a larger shift occurring in 2011 in the Company s business to states with higher income tax rates. The overall rate was lower in 2012 as a result of the Company consolidating 100% of the pre-tax income related to the noncontrolling public limited partners share of partnership earnings but does not record an income tax provision with respect to the portion of the Partnership s earnings allocated to its noncontrolling public limited partners.

The following table reconciles the beginning and ending amount of reserve for uncertain tax positions (excluding interest and penalties):

	2013	2012 (Thousands)	2011
Balance at January 1	$ 17,858	$ 30,730	$ 37,943
Additions based on tax positions related to current year	49,289	2,165	1,245
Additions for tax positions of prior years		2,320	184
Settlements			
Reductions for tax positions of prior years	(790)	(12,235)	(7,886)
Lapse of statute of limitations	(9,270)	(5,122)	(756)
Balance at December 31	$ 57,087	$ 17,858	$ 30,730

Included in the tabular reconciliation above at December 31, 2013, 2012 and 2011 are $7.6 million, $6.4 million and $15.9 million, respectively, for tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of tax deductions. Because of the impact of deferred tax accounting, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash taxes to an earlier period. Additionally, there are uncertain tax positions of $9.8 million and

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$14.6 million for the years ended December 31, 2013 and 2012, respectively, that are included in the tabular reconciliation above, but recorded in the Consolidated Balance Sheets as a reduction of the related deferred tax asset for NOLs and R&E tax credit carryforwards.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company reversed approximately $0.5 million, $1.8 million and $9.7 million of previously recorded interest expense in 2013, 2012 and 2011, respectively. Interest and penalties of $0.2 million, $0.5 million and $2.3 million were included in the balance sheet reserve at December 31, 2013, 2012 and 2011, respectively.

There were no material changes to the Company s methodology for unrecognized tax benefits during 2013. The total amount of unrecognized tax benefits (excluding interest and penalties) that, if recognized, would affect the effective tax rate was $33.3 million, $5.3 million and $5.2 million as of December 31, 2013, 2012 and 2011, respectively.

Decreases to the unrecognized tax benefits during 2013, 2012, and 2011 were primarily attributable to the reversal of certain prior year tax positions related to state taxes and the related interest expense as well as the lapse of applicable statutes of limitations. As of December 31, 2013, the Company does not expect any of its unrecognized tax benefits to decrease within the next 12 months due to potential settlements with taxing authorities, legal or administrative guidance by relevant taxing authorities or the lapse of applicable statutes of limitation.

The consolidated federal income tax liability of the Company has been settled with the Internal Revenue Service through 2009 and the 2010 and 2011 tax years are currently under examination. The Company also is the subject of various state income tax examinations. The Company believes that it is appropriately reserved for uncertain tax positions.

The following table summarizes the source and tax effects of temporary differences between financial reporting and tax bases of assets and liabilities:

	As of December 31,	
	2013	2012
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets .	$ (670,368)	$ (696,252)
Total deferred income tax liabilities	2,295,128	2,122,377
Total net deferred income tax liabilities	1,624,760	1,426,125
Total deferred income tax liabilities (assets)		
Drilling and development costs expensed for income tax reporting	1,181,375	933,800

Tax depreciation in excess of book depreciation		923,443		924,229
Investment in Partnership		101,569		108,764
Accumulated OCI		28,597		81,087
Post-retirement benefits		(3,946)		(3,784)
Incentive compensation		(60,982)		(28,811)
Alternative minimum tax credit carryforward		(246,157)		(69,901)
Net operating loss carryforwards		(359,283)		(593,756)
Other		3,740		8,261
Total excluding valuation allowances		1,568,356		1,359,889
Valuation allowance		56,404		66,236
Total (including amounts classified as current assets of $31,005 and $15,946, respectively)	$	1,624,760	$	1,426,125

The net deferred tax liability relating to the Company s accumulated OCI balance as of December 31, 2013 consisted of a $38.7 million deferred tax liability related to the Company s net unrealized gain from hedging transactions, a $5.3 million deferred tax asset related to other post-retirement benefits, and a $4.8 million deferred tax asset related to the Company s pension plans. The net deferred tax liability relating to the Company s accumulated OCI balance as of December 31, 2012 consisted of an $88.8 million deferred tax liability related to the

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Company s net unrealized gain from hedging transactions, a $3.6 million deferred tax asset related to other post-retirement benefits, and a $4.1 million deferred tax asset related to the Company s pension plans.

The Company also has a total deferred tax asset of $183.2 million at December 31, 2013 related to the federal NOL carryforward from 2012 of $166.1 million and 2011 of $17.1 million, respectively. The deferred tax asset has been increased for uncertain tax positions of approximately $10.6 million as of December 31, 2013, and reduced for approximately $3.7 million as of December 31, 2012. The federal NOL carryforward period is 20 years and, if unused, the loss carryforward, in excess of the 2013 NOL utilization, for 2012 and 2011 will expire in 2032 and 2031, respectively.

The Company is subject to the AMT if the computed AMT liability exceeds the regular tax liability for the year. As a result of certain AMT preference items related to IDCs, the Company has generated AMT carryforwards. Because AMT taxes paid can be credited against regular tax and have an indefinite carryforward period, this item is reflected as a deferred tax asset on the Company s Consolidated Balance Sheets.

As of December 31, 2013, the Company had a deferred tax asset of $118.2 million, net of valuation allowances of $56.4 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2014 to 2033. As of December 31, 2012, the Company had a deferred tax asset of $86.0 million, net of valuation allowances of $66.2 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2013 to 2032. The deferred tax asset has been reduced for uncertain tax positions of approximately $0.5 million during the years ended December 31, 2013 and 2012, respectively.

During the years ended December 31, 2012 and 2011, share-based payment arrangements paid in stock generated an $8.1 million and $6.6 million excess tax benefit, respectively, which was not recorded in the financial statements as an addition to common stockholders equity due to the Company s NOL position. Due to taxable income generated in the year ended December 31, 2013, the Company has recorded tax benefits of $12.2 million in the financial statements as an addition to common stockholders equity as these tax benefits reduced taxes payable in the current year. The Company uses tax law ordering when determining when excess tax benefits have been realized.

10. Equity in Nonconsolidated Investments

The Company has ownership interests in nonconsolidated investments that are accounted for under the equity method of accounting. The following table summarizes the Company s equity in the nonconsolidated investments:

Investees	Location	Interest Type	Ownership as of December 31, 2013	As of December 31, 2013	2012
				(Thousands)	
Nora Gathering, LLC (Nora LLC)	USA	Joint	50%	$ 128,983	$ 130,368

The Company s ownership share of the earnings for 2013, 2012 and 2011 related to the total investments accounted for under the equity method was $7.6 million, $6.1 million and $7.2 million, respectively, reported in other income on the Statements of Consolidated Income. Also included in its ownership share of the earnings of equity method investments for the year ended December 31, 2011 was the Company s equity earnings related to its equity investment in Appalachian Natural Gas Trust (ANGT), which no longer exists due to the ANPI transaction. See Note 8 for further details.

EQT Midstream s equity investment in Nora LLC represents a 50% ownership interest which was obtained during 2007 through a series of transactions with Pine Mountain Oil and Gas, Inc., a subsidiary of Range Resources Corporation, by contributing Nora area gathering property in exchange for the ownership interest. EQT Midstream made no additional equity investments in Nora LLC during 2012 or 2013.

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The following tables summarize the unaudited condensed financial statements for nonconsolidated investments accounted for under the equity method of accounting for the periods noted:

Summarized Balance Sheets

	As of December 31,	
	2013	2012
	(Thousands)	
Current assets	$ 27,014	$ 15,966
Noncurrent assets	239,583	249,347
Total assets	$ 266,597	$ 265,313
Current liabilities	$ 8,529	$ 4,476
Stockholders equity	258,068	260,837
Total liabilities and stockholders equity	$ 266,597	$ 265,313

Summarized Statements of Income

	Years Ended December 31,		
	2013	2012	2011
	(Thousands)		
Revenues	$ 45,040	$ 47,888	$ 49,772
Operating expenses	29,810	35,596	35,520
Net income	$ 15,230	$ 12,292	$ 14,252

11. Short-Term Loans

As of December 31, 2013, the Company had a $1.5 billion revolving credit facility that expires on December 8, 2016. The Company may request two one-year extensions of the expiration date subject to satisfaction of certain conditions.

The revolving credit facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes. Subject to certain terms and conditions, the Company may, on a one-time basis, request that the lenders commitments be increased to an aggregate amount up to $2.0 billion. Each lender in the facility may decide if it will increase its commitment. The credit facility is underwritten by a syndicate of 16 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. The Company s obligations under the credit facility are unsecured.

The Company is not required to maintain compensating bank balances. The Company s debt issuer credit ratings, as determined by S&P, Moody s or Fitch Ratings Service on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with its lines of credit in addition to the interest rate charged by the counterparties on any amounts borrowed against the lines of credit; the lower the Company s debt credit rating, the higher the level of fees and borrowing rate.

As of December 31, 2013, the Partnership had a $350 million revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, and a syndicate of lenders, which will expire on July 2, 2017. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. The Company is not a guarantor of the Partnership s obligations under the credit facility. The Partnership s obligations under the revolving portion of the credit facility are unsecured.

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As of December 31, 2013 and 2012, neither the Company nor the Partnership had loans or letters of credit outstanding under their respective revolving credit facilities. Commitment fees averaging approximately 24 basis points for the year ended December 31, 2013 and 25 basis points for the year ended December 31, 2012 were incurred to maintain credit availability under the Company s revolving credit facility. The Partnership incurred commitment fees averaging approximately 25 basis points for the years ended December 31, 2013 and 2012 to maintain credit availability under its revolving credit facility.

The maximum amount of outstanding short-term loans at any time under the Company s credit facility during the years ended December 31, 2013 and 2011 was $178.5 million and $104.0 million, respectively. The Company did not have any short-term loans outstanding at any time during the year ended December 31, 2012. The average daily balance of short-term loans outstanding for the Company during the year ended December 31, 2013 was approximately $12.1 million at a weighted average annual interest rate of 1.67%. The average daily balance of short-term loans outstanding for the Company during the year ended December 31, 2011 was approximately $5.5 million at a weighted average annual interest rate of 1.81%. The Partnership had no short-term loans outstanding at any time during the years ended December 31, 2013 or 2012.

The Company s debt agreements and other financial obligations contain various provisions that, if not complied with, could result in termination of the agreements, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the debt agreements relate to maintenance of a debt-to-total capitalization ratio, limitations on transactions with affiliates, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company s credit facility contains financial covenants that require a total debt-to-total capitalization ratio of no greater than 65%. The calculation of this ratio excludes the effects of accumulated OCI. As of December 31, 2013, the Company was in compliance with all debt provisions and covenants.

The Partnership s credit facility contains various provisions that, if not complied with, could result in the termination of the credit facility, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the credit facility related to maintenance of permitted leverage coverage and interest coverage ratios, limitations on transactions with affiliates, insolvency events, nonpayment of schedule principal or interest payments, acceleration of other financial obligations and change of control provisions. Under the credit facility, the Partnership is required to maintain a consolidated leverage ratio of not more than 5.00 to 1.00 (or, after the Partnership obtains an investment grade rating, not more than 5.50 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and, until the Partnership obtains an investment grade rating, a consolidated interest coverage ratio of not less than 3.00 to 1.00. As of December 31, 2013, the Partnership was in compliance with all credit facility provisions and covenants.

12. Long-Term Debt

	As of December 31,	
	2013	**2012**

	(Thousands)	
7.76% notes, due 2014 thru 2016	$ 18,316	$ 32,973
5.00% notes, due October 1, 2015	150,000	150,000
5.15% notes, due March 1, 2018	200,000	200,000
6.50% notes, due April 1, 2018	500,000	500,000
8.13% notes, due June 1, 2019	700,000	700,000
4.88% notes, due November 15, 2021	750,000	750,000
7.75% debentures, due July 15, 2026	115,000	115,000
Medium-term notes:		
8.7% to 9.0% Series A, due 2014 thru 2021	40,200	40,200
7.3% to 7.6% Series B, due 2015 thru 2023	20,000	30,000
7.6% Series C, due 2018	8,000	8,000
	2,501,516	2,526,173
Less debt payable within one year	11,162	23,204
Total long-term debt	$ 2,490,354	$ 2,502,969

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The indentures and other agreements governing the Company s indebtedness contain certain restrictive financial and operating covenants, including covenants that restrict the Company s ability to incur indebtedness, incur liens, enter into sale and leaseback transactions, complete acquisitions, merge, sell assets and perform certain other corporate actions. The covenants do not contain a rating trigger. Therefore, a change in the Company s debt rating would not trigger a default under the indentures and other agreements governing the Company s indebtedness.

Aggregate maturities of long-term debt are $11.2 million in 2014, $166.0 million in 2015, $3.0 million in 2016, zero in 2017 and $708.0 million in 2018.

13. Pension and Other Post-Retirement Benefit Plans

The following table sets forth the defined benefit pension and other post-retirement benefit plans funded status and amounts recognized for those plans in the Company s Consolidated Balance Sheets. Refer to Note 2 for further information related to the Equitable Gas Transaction.

	For the Years Ended December 31,			
	2013	2012	2013	2012
	Pension Benefits		Other Benefits	
	(Thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 63,270	$ 61,885	$ 36,255	$ 35,293
Service cost	500	500	905	737
Interest cost	1,935	2,448	1,110	1,427
Amendments		(126)		
Actuarial loss	(3,038)	5,733	(2,355)	2,656
Benefits paid	(5,269)	(5,571)	(3,961)	(3,858)
Expenses paid	(493)	(511)		
Divestitures	(34,410)		(13,701)	
Settlements	(667)	(1,088)		
Subtotal	21,828	63,270	18,253	36,255
Benefit obligation included in discontinued operations		42,835		15,577
Benefit obligation at end of year	$ 21,828	$ 20,435	$ 18,253	$ 20,678
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 46,984	$ 45,951	$ 165	$ 19
Actual gain on plan assets	7,304	5,346		
Contributions	2,639	2,857	328	146
Benefits paid	(5,269)	(5,571)		

Expenses paid	(493)	(511)		
Divestitures	(30,409)			
Settlements	(667)	(1,088)		
Subtotal	20,089	46,984	493	165
Fair value of plan assets included in discontinued operations		30,428		
Fair value of plan assets at end of year	20,089	16,556	493	165
Funded status at end of year	$ (1,739)	$ (3,879)	$ (17,760)	$ (20,513)

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Amounts recognized in the statement of financial position consist of:				
Current liabilities	$	$	$ (1,341)	$ (3,353)
Noncurrent liabilities	(1,739)	(3,879)	(16,419)	(17,160)
Net amounts recognized	$ (1,739)	$ (3,879)	$ (17,760)	$ (20,513)
Amounts recognized in accumulated OCI, net of tax, consist of:				
Net loss	$ 7,524	$ 24,634	$ 8,234	$ 14,291
Net prior service (credit)			106	(1,560)
Net amount recognized	$ 7,524	$ 24,634	$ 8,340	$ 12,731

The accumulated benefit obligation for the Company s defined benefit pension plans was $21.8 million and $20.4 million at December 31, 2013 and 2012, respectively. The Company uses a December 31 measurement date for its defined benefit pension and other post-retirement benefit plans.

The Company s costs related to its defined benefit pension and other post-retirement benefit plans were as follows:

	For the Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
		Pension Benefits			Other Benefits	
			(Thousands)			
Components of net periodic benefit cost:						
Service cost	$ 500	$ 500	$ 500	$ 905	$ 737	$ 620
Interest cost	1,935	2,448	3,115	1,110	1,427	1,771
Expected return on plan assets	(3,323)	(3,712)	(4,070)			
Amortization of prior service cost				(845)	(845)	(902)
Recognized net actuarial loss	2,306	1,880	1,471	1,760	1,671	1,605
Settlement loss and special termination benefits	381	725	530			
Subtotal	1,799	1,841	1,546	2,930	2,990	3,094
Net periodic benefit cost of discontinued operations	1,552	1,586	1,387	1,356	1,288	1,427
Net periodic benefit cost	$ 247	$ 255	$ 159	$ 1,574	$ 1,702	$ 1,667

Currently, the Company recognizes expense for on-going post-retirement benefits other than pensions, a portion of which expense is subject to recovery in the approved rates of its rate-regulated Midstream business.

For the Years Ended December 31,

	2013	2012	2011	2013	2012	2011
		Pension Benefits			Other Benefits	
			(Thousands)			
Other changes in plan assets and benefit obligations recognized in OCI, net of tax:						
Net (gain) loss	$ 712	$ 261	$ 3,378	$ 2,147	$ 494	$ 181
Net prior service cost				416	330	915
Total recognized in OCI, net of tax	$ 712	$ 261	$ 3,378	$ 2,563	$ 824	$ 1,096
Total recognized in net periodic benefit cost and OCI, net of tax	$ 959	$ 2,102	$ 4,924	$ 4,137	$ 3,814	$ 4,190

The net loss and prior service cost associated with the disposal group of the Equitable Gas Transaction totaled $17.3 million, net of tax, at the closing date of the Equitable Gas Transaction. The Company recognized the full amount in income from discontinued operations in the Statements of Consolidated Income for the year ended December 31, 2013.

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The estimated net loss for the defined benefit pension plans that will be amortized from accumulated OCI, net of tax, into net periodic benefit cost during 2014 is $0.4 million. The estimated net loss and net prior service (credit) for the other post-retirement benefit plans that will be amortized from accumulated OCI, net of tax, into net periodic benefit cost during 2014 are $0.4 million and $(0.3 million), respectively.

The following weighted average assumptions were used to determine the benefit obligations for the Company s defined benefit pension and other post-retirement benefit plans:

	December 31,			
	2013	2012	2013	2012
	Pension Benefits		Other Benefits	
Discount rate	4.00%	3.25%	4.00%	3.25%
Rate of compensation increase	N/A	N/A	N/A	N/A

The following weighted average assumptions were used to determine the net periodic benefit cost for the Company s defined benefit pension and other post-retirement benefit plans:

	For the Years Ended December 31,			
	2013	2012	2013	2012
	Pension Benefits		Other Benefits	
Discount rate	3.25%	4.25%	3.25%	4.25%
Expected return on plan assets	7.75%	7.75%	N/A	N/A
Rate of compensation increase	N/A	N/A	N/A	N/A

The expected rate of return is established at the beginning of the fiscal year to which it relates based upon information available to the Company at that time, including the plans investment mix and the forecasted rates of return on the types of securities held. The Company considered the historical rates of return earned on plan assets, an expected return percentage by asset class based upon a survey of investment managers and the Company s actual and targeted investment mix. Any differences between actual experience and assumed experience are deferred as an unrecognized actuarial gain or loss. The unrecognized actuarial gains or losses are amortized into the Company s net periodic benefit cost. The expected rate of return determined as of January 1, 2014 is 7.75%. This assumption will be used to derive the Company s 2014 net periodic benefit cost. The rate of compensation increase is not applicable in determining future benefit obligations as a result of plan design. Pension expense increases or decreases as the expected rate of return or discount rate is changed.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2013 was 7.00% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.00% in 2018.

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

	One-Percentage-Point Increase			One-Percentage-Point Decrease		
	2013	2012	2011	2013	2012	2011
			(Thousands)			
Increase (decrease) to total of service and interest cost components	$ 25	$ 32	$ 40	$ (26)	$ (32)	$ (39)
Increase (decrease) to post-retirement benefit obligation	$ 220	$ 711	$ 730	$ (223)	$ (688)	$ (702)

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The Company s pension asset allocation at December 31, 2013 and 2012 and target allocation for 2014 by asset category are as follows:

Asset Category	Target Allocation 2014	Percentage of Plan Assets at December 31, 2013	2012
Domestic broadly diversified equity securities	40% - 60%	42%	53%
Fixed income securities	20% - 50%	29%	32%
International broadly diversified equity securities	5% - 15%	7%	10%
Alternative fixed income securities	0% - 10%	4%	4%
Cash and equivalent investments	0% - 15%	18%	1%
		100%	100%

The investment activities of the Company s pension plan are supervised and monitored by the Benefits Investment Committee (BIC). The BIC reports to the Management Development and Compensation Committee (the Compensation Committee) of the Board of Directors and consists of the Chief Financial Officer and other officers and employees of the Company. The BIC has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the BIC are to minimize high levels of risk at the total pension investment fund level. The BIC monitors the asset allocation on a quarterly basis and adjustments are made, as needed, to rebalance the assets within the prescribed target ranges. Comparative market and peer group benchmarks are utilized to ensure that each of the firm s investment managers is performing satisfactorily.

The cash and equivalent investments category is outside of the target allocation as a result of liquidating investments for transfer to the Peoples Natural Gas Company LLC DB Plan for Former Employees of Equitable Gas Company based upon a preliminary asset allocation calculation in connection with the Equitable Gas Transaction. The excess cash investment balance is temporary and a portion will be re-invested in other assets in the first quarter of 2014, which will realign the investment balances with the target allocation.

The Company made cash contributions of approximately $2.6 million, $2.9 million and $4.3 million to its pension plan during 2013, 2012 and 2011, respectively, to meet certain funding targets. The Company expects to make cash payments of at least $0.4 million related to its pensions during 2014, which will meet minimum required contributions and the 80% funding obligation on the pension plan. Pension plan cash contributions are designed to at least meet requirements of the 80% funding level. The dollar amount of a cash contribution made in any particular year will vary as a result of gains or losses sustained by the pension plan during the year due to market conditions. The Company does not expect these variations to have a significant effect on its financial position, results of operations or liquidity.

The following pension benefit payments, which reflect expected future service, are expected to be paid by the plan during each of the next five years and the five years thereafter: $2.5 million in 2014; $2.2 million in 2015; $2.0 million in 2016; $1.8 million in 2017; $1.9 million in 2018; and $8.4 million in the five years thereafter.

The following benefit payments for post-retirement benefits other than pensions, which reflect expected future service, are expected to be paid by the Company during each of the next five years and the five years thereafter: $1.9 million in 2014; $1.8 million in 2015; $1.8 million in 2016; $1.7 million in 2017; $1.7 million in 2018; and $7.7 million in the five years thereafter.

Expense recognized by the Company related to its defined contribution plans totaled $14.6 million in 2013, $12.0 million in 2012 and $10.1 million in 2011.

The Company reports defined benefit plan assets at fair value which is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The disclosure below categorizes the assets by a fair value hierarchy. Assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. The three levels of the hierarchy are defined as follows:

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Level 1 Observable inputs based on quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 Observable inputs, other than those included in Level 1, based on quoted prices for similar assets or liabilities in active markets or quoted prices for identical assets and liabilities in inactive markets.

Level 3 Unobservable inputs that reflect an entity s own assumptions about what inputs a market participant would use in pricing the asset or liability based on the best information available in the circumstances.

Defined benefit plan asset investments include mutual funds with a fair value of $6.9 million and $8.8 million as of December 31, 2013 and 2012, respectively. These investments are based upon daily unadjusted quoted prices and therefore are considered Level 1.

Defined benefit plan asset investments also include common/collective trusts with a fair value of $13.2 million and $38.2 million as of December 31, 2013 and 2012, respectively. These investments are valued at current market value of the underlying assets of the fund and therefore are considered Level 2.

Assets classified as Level 1 transferred to Level 2 during the year ended December 31, 2012 were $9.8 million due to the plan severing its investment in a bond mutual fund and investing in a bond portfolio. This change provided the ability to manage these investments by individual performance. There were no changes in risk, exposure or asset allocation.

As of December 31, 2013 and 2012, the defined benefit plan did not hold any assets whose fair value was determined using unobservable inputs and therefore would be considered Level 3.

14. Changes in Accumulated Other Comprehensive Income by Component

The following tables explain the changes in accumulated OCI by component for the year ended December 31, 2013:

	Year Ended December 31, 2013							
	Natural gas cash flow hedges, net of tax		Interest rate cash flow hedges, net of tax		Pension and other post-retirement benefits liability adjustment, net of tax		Accumulated OCI (loss), net of tax	
	(Thousands)							
Accumulated OCI (loss), net of tax, as of January 1, 2013	$ 138,188		$ (1,276)		$ (37,365)		$ 99,547	
Gains recognized in accumulated OCI, net of tax	10,669	(a)			2,081		12,750	
Amounts reclassified from accumulated OCI into realized (income) expense, net of tax	(87,158)	(a)	144	(a)	19,420	(b)	(67,594)	
Change in accumulated OCI, net of tax	(76,489)		144		21,501		(54,844)	
Accumulated OCI (loss), net of tax, as of December 31, 2013	$ 61,699		$ (1,132)		$ (15,864)		$ 44,703	

(a) See Note 5 for additional information.

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(b) This accumulated OCI reclassification is attributable to the net actuarial loss and net prior service cost related to the Company s defined benefit pension plans and other post-retirement benefit plans. See Note 13 for additional information.

15. Common Stock and Earnings Per Share

Common Stock

At December 31, 2013, shares of EQT s authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	8,911
Total	29,368

Earnings Per Share

The computation of basic and diluted earnings per share of common stock attributable to EQT Corporation is shown in the table below:

	Years Ended December 31,		
	2013	**2012**	**2011**
	(Thousands except per share amounts)		
Basic earnings per common share:			
Net income attributable to EQT Corporation	$ 390,572	$ 183,395	$ 479,769
Average common shares outstanding	150,574	149,619	149,392
Basic earnings per common share	$ 2.59	$ 1.23	$ 3.21
Diluted earnings per common share:			
Net income attributable to EQT Corporation	$ 390,572	$ 183,395	$ 479,769
Average common shares outstanding	150,574	149,619	149,392
Potentially dilutive securities:			

Stock options and awards (a)	1,213	887	817
Total	151,787	150,506	150,209
Diluted earnings per common share	$ 2.57	$ 1.22	$ 3.19

(a) There were no options to purchase common stock which were excluded from potentially dilutive securities because they were anti-dilutive for the year ended December 31, 2013. Options to purchase common stock which were excluded from potentially dilutive securities because they were anti-dilutive totaled 281,528 and 6,480 shares for the year ended December 31, 2012 and 2011, respectively.

The impact of the Partnership s dilutive units did not have a material impact on the Company s earnings per share calculations for any of the periods presented.

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16. Share-Based Compensation Plans

Share-based compensation expense recorded by the Company was as follows:

	Years Ended December 31, 2013	2012	2011
		(Thousands)	
2008 Executive Performance Incentive Program	$	$	$ 923
2010 Executive Performance Incentive Programs		1,940	2,118
2012 Executive Performance Incentive Program	6,739	10,633	
2013 Executive Performance Incentive Program	6,602		
2007 Supply Long-Term Incentive Program			198
2010 Stock Incentive Award Program		4,022	4,241
2011 EQT Value Driver Award Program		3,033	15,807
2012 EQT Value Driver Award Program	2,327	11,557	
2013 EQT Value Driver Award Program	13,050		
2011 Volume and Efficiency Program	13,834	5,286	5,384
Restricted stock awards	3,033	2,007	1,929
Non-qualified stock options	3,805	3,580	6,057
Non-employee directors share-based awards	7,432	2,558	3,320
EQM Total Return Program	837	419	
EQM non-employee directors share-based awards	144	116	
Expense attributable to discontinued operations	741	670	352
Total share-based compensation expense	$ 58,544	$ 45,821	$ 40,329

The Company typically uses treasury stock to fund awards that are paid in stock. When an award has graduated vesting, the Company records the expense equal to the vesting percentage on the vesting date. A portion of the expense related to share-based compensation plans is included as an unallocated expense in deriving total operating income for segment reporting purposes. See Note 4.

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2013, 2012 and 2011 were $32.9 million, $7.9 million and $3.1 million, respectively. During the years ended December 31, 2013, 2012 and 2011, share-based payment arrangements paid in stock generated tax benefits of $14.4 million, $15.1 million and $8.1 million, respectively. As a result of the Company s NOL position in 2012 and 2011, excess tax benefits of $8.1 million and $6.6 million, respectively, were not recorded in the financial statements as an addition to common stockholders equity. For share-based payment arrangements paid in cash, the Company recognizes tax benefits at the effective tax rate, except as limited by Section 162(m) of the Internal Revenue Code.

Executive Performance Incentive Programs

In 2008, the Compensation Committee of the Board of Directors adopted the 2008 Executive Performance Incentive Program (2008 EPIP) under the 1999 Long-Term Incentive Plan. The 2008 EPIP was established to provide long-term incentive opportunities to key executives to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. The vesting of the stock units granted under the 2008 EPIP occurred on December 31, 2011, after the ordinary close of the performance period. The vesting resulted in approximately 44,400 units (75% of the award) with a value of approximately $2.5 million being distributed in cash on December 31, 2011. The Company accounted for these awards as liability awards and as such recorded compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. The 2008 EPIP expense was classified as selling, general and administrative expense in the Statements of Consolidated Income.

In 2009, the Compensation Committee of the Board of Directors adopted the 2010 Executive Performance Incentive Program (2010 EPIP) and the 2010 July Executive Performance Incentive Program (the 2010 July EPIP,

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and together with the 2010 EPIP, the 2010 EPIPs) under the 2009 Long-Term Incentive Plan. The 2010 EPIPs were established to provide long-term incentive opportunities to key employees to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. The vesting of the units under the 2010 EPIPs occurred on December 31, 2012, after the ordinary close of the respective performance periods. Awards granted were earned based on a combination of the level of total shareholder return relative to the respective peer groups over the period January 1, 2010 (July 1, 2010 for the 2010 July EPIP) through December 31, 2012 and the level of production sales revenues over the period January 1, 2010 (July 1, 2010 for the 2010 July EPIP) through September 30, 2012. The Company accounted for these awards as equity awards using the $60.09 grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance periods. The prices were generated using each company s annual volatility for the expected term and the commensurate three-year risk-free rate of 1.69%. Based on the Company s performance relative to the conditions discussed above, 115,590 shares of common stock, valued at $6.9 million based on the Monte Carlo value on the grant date, were distributed on December 31, 2012.

In 2012, the Compensation Committee of the Board of Directors adopted the 2012 Executive Performance Incentive Plan (2012 EPIP) under the 2009 Long-Term Incentive Plan. The 2012 EPIP was established to provide long-term incentive opportunities to key employees to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. A total of 351,480 units were outstanding at January 1, 2013. Adjusting for 16,425 forfeitures, there were 335,055 outstanding units as of December 31, 2013. The vesting of the units under the 2012 EPIP will occur upon payment after December 31, 2014 (the end of the performance period). The payout factor will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group and the level of cumulative operating cash flow per share over the period January 1, 2012 through December 31, 2014. The Company accounted for these awards as equity awards using the grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance period. The prices were generated using each company s annual volatility for the expected term and the commensurate three-year risk-free rate of 0.36%. As the program includes a performance condition that affects the number of shares that will ultimately vest (the cumulative operating cash flow per share performance condition), in accordance with Accounting Standards Codification (ASC) Topic 718, the Monte Carlo simulation computed a grant date fair value for each possible performance condition outcome on the grant date. The Company reevaluates the probable outcome at each reporting period, in order to record expense at the then-probable outcome grant date fair value. As of December 31, 2013, the compensation expense was recorded using a grant date fair value of $123.37, which was the grant date fair value computed for the outcome which management estimated to be most probable. The total compensation cost capitalized in 2013 and 2012 was $8.1 million and $2.1 million, respectively. As of December 31, 2013, $13.8 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2012 EPIP was expected to be recognized by December 31, 2014.

The peer companies for the 2012 EPIP are as follows:

Cabot Oil & Gas Corp.	National Fuel Gas Company	Sempra Energy
Chesapeake Energy Corp.	NStar Electric Co.	SM Energy Company
Cimarex Energy Co.	ONEOK, Inc.	Southwestern Energy Company
CONSOL Energy Inc.	Penn Virginia Corp.	Spectra Energy Corp
Energen Corp.	Pioneer Natural Resources Company	Ultra Petroleum Corp.
EOG Resources, Inc.	Plains Exploration & Production Co.	Whiting Petroleum Corp.
EXCO Resources, Inc.	Questar Corp.	The Williams Companies, Inc.

MarkWest Energy Partners, L.P.	Quicksilver Resources Inc.
MDU Resources Group, Inc.	Range Resources Corp.

In 2013, the Compensation Committee of the Board of Directors adopted the 2013 Executive Performance Incentive Plan (2013 EPIP) under the 2009 Long-Term Incentive Plan. The 2013 EPIP was established to provide long-term incentive opportunities to key employees to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. A total of 314,280 units were granted in 2013 and no additional units may be granted. Adjusting for 16,683 forfeitures, there were 297,597 outstanding units as of December 31, 2013. The vesting of the units under the 2013 EPIP will occur upon payment after December 31, 2015

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(the end of the performance period). The payout factor will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group and the level of cumulative operating cash flow per share over the period January 1, 2013 through December 31, 2015. The Company accounted for these awards as equity awards using the grant date fair value as determined using a Monte Carlo simulation. The Monte Carlo simulation projected the share price, for the Company and its peers, at the ending point of the performance period. The prices were generated using each company s annual volatility for the expected term and the commensurate three-year risk-free rate of 0.36%. As the program includes a performance condition that affects the number of shares that will ultimately vest (the cumulative operating cash flow per share performance condition), in accordance with ASC Topic 718, the Monte Carlo simulation computed a grant date fair value for each possible performance condition outcome on the grant date. The Company reevaluates the then-probable outcome at each reporting period, in order to record expense at the probable outcome grant date fair value. As of December 31, 2013, the compensation expense was recorded using a grant date fair value of $126.45 per unit, which was the grant date fair value computed for the outcome which management estimated to be most probable. The total compensation cost capitalized in 2013 was $5.0 million. As of December 31, 2013, $23.2 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2013 EPIP was expected to be recognized over the next two years.

The peer companies for the 2013 EPIP are as follows:

Cabot Oil & Gas Corp.	MDU Resources Group, Inc.	Sempra Energy
Chesapeake Energy Corp.	National Fuel Gas Company	SM Energy Company
Cimarex Energy Co.	Newfield Exploration Company	Southwestern Energy Company
Concho Resources, Inc	ONEOK, Inc.	Spectra Energy Corp
CONSOL Energy Inc.	Pioneer Natural Resources Company	Ultra Petroleum Corp.
Energen Corp	Plains Exploration & Production Co.	Whiting Petroleum Corp.
EOG Resources, Inc.	Questar Corp.	The Williams Companies, Inc.
EXCO Resources, Inc.	Quicksilver Resources Inc.	
MarkWest Energy Partners, L.P.	Range Resources Corp.	

2010 Stock Incentive Award Program

Effective in 2010, the Compensation Committee of the Board of Directors adopted the 2010 Stock Incentive Award Program (2010 SIA) under the 2009 Long-Term Incentive Plan. The 2010 SIA was established to provide long-term incentive opportunities to key employees to further align their interests with those of the Company s shareholders and with the strategic objectives of the Company. The payout opportunity with respect to the performance awards was contingent upon adjusted 2010 earnings before interest, taxes, depreciation and amortization (EBITDA) performance as compared to the Company s annual business plan and individual, business unit and Company value driver performance over the period January 1, 2010 through December 31, 2010. The vesting of the awards occurred on December 31, 2012. The vesting resulted in 294,925 awards valued at $12.6 million based on the grant date fair value, being distributed in Company common stock on December 31, 2012.

Value Driver Award Programs

Effective in 2011, the Compensation Committee of the Board of Directors adopted the 2011 Value Driver Award Program (2011 EQT VDA) under the 2009 Long-Term Incentive Plan. The 2011 EQT VDA was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under the 2011 EQT VDA, 50% of the units confirmed vested upon payment following the first anniversary of the grant date; the remaining 50% of the units confirmed vested on December 31, 2012. The payments were contingent upon adjusted 2011 EBITDA performance as compared to the Company s annual business plan and individual, business unit and Company value driver performance over the period January 1, 2011 through December 31, 2011. The two tranches of awards vested and were distributed in cash payouts of $14.6 million in February 2012 and $15.3 million on December 31, 2012. The Company accounted for these awards as liability awards and as such, recorded compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. Due to the graded vesting of the award, the Company recognized compensation cost over the requisite service period for each separately vesting tranche of the award as though the award was, in substance, multiple awards.

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Effective in 2012, the Compensation Committee of the Board of Directors adopted the 2012 Value Driver Award Program (2012 EQT VDA) under the 2009 Long-Term Incentive Plan. The 2012 EQT VDA was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under the 2012 EQT VDA, 50% of the units confirmed vested upon payment following the first anniversary of the grant date; the remaining 50% of the units confirmed vested upon the payment date following the second anniversary of the grant date. The payments were contingent upon adjusted 2012 EBITDA performance as compared to the Company s annual business plan and individual, business unit and Company value driver performance over the period January 1, 2012 through December 31, 2012. As of January 1, 2013, 409,357 awards including accrued dividends were outstanding under the 2012 EQT VDA. The first tranche of the confirmed awards vested and 204,679 awards were distributed in Company common stock in January 2013. The remainder of the confirmed awards vested and were paid in Company common stock in February 2014. As of December 31, 2013, 196,609 awards including accrued dividends were outstanding under the 2012 EQT VDA. The Company accounts for these awards as equity awards using the $54.79 grant date fair value per unit which was equal to the Company s common stock price on the date prior to the date of grant. Due to the graded vesting of the award, the Company recognizes compensation cost over the requisite service period for each separately vesting tranche of the award as though the award was, in substance, multiple awards. The total compensation cost capitalized was $2.6 million and $5.0 million in 2013 and 2012, respectively.

Effective in 2013, the Compensation Committee of the Board of Directors adopted the 2013 Value Driver Award Program (2013 EQT VDA) under the 2009 Long-Term Incentive Plan. The 2013 EQT VDA was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under the 2013 EQT VDA, 50% of the units confirmed vested upon payment following the first anniversary of the grant date; the remaining 50% of the units confirmed will vest upon the payment date following the second anniversary of the grant date. The payments are contingent upon adjusted 2013 EBITDA performance as compared to the Company s annual business plan and individual, business unit and Company value driver performance over the period January 1, 2013 through December 31, 2013. As of December 31, 2013, 614,048 awards including accrued dividends were outstanding under the 2013 EQT VDA. The first tranche of the confirmed awards vested and were distributed in Company common stock in February 2014. The remainder of the confirmed awards is expected to vest and be paid in Company common stock in the first quarter of 2015. The Company accounts for these awards as equity awards using the $58.98 grant date fair value per unit which was equal to the Company s common stock price on the date prior to the date of grant. Due to the graded vesting of the award, the Company recognizes compensation cost over the requisite service period for each separately vesting tranche of the award as though the award was, in substance, multiple awards. The total compensation cost capitalized in 2013 was $14.1 million. As of December 31, 2013, $9.0 million of unrecognized compensation cost related to the 2013 EQT VDA was expected to be fully recognized by December 31, 2014.

2011 Volume and Efficiency Program

Effective in 2011, the Compensation Committee of the Board of Directors adopted the 2011 Volume and Efficiency Program (2011 VEP) under the 2009 Long-Term Incentive Plan. The 2011 VEP was established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. The payout opportunity with respect to the target awards is anticipated to be 300% of the outstanding units based on the achievement of predetermined specified performance measures. Payment of the awards will be distributed in Company common stock during the first quarter 2014 after the end of the performance period on December 31, 2013. The Company accounts for these awards as equity awards using the $48.06 grant date fair value per unit which was equal to the Company s common stock price on the grant date. As of January 1, 2013, 228,640 awards were outstanding. Adjusting for forfeitures of 7,500, there were 221,140 awards outstanding as of December 31, 2013, not including an adjustment for the performance multiplier. The total compensation cost capitalized was $2.8 million,

$2.5 million and $1.9 million in 2013, 2012 and 2011, respectively. As of December 31, 2013, compensation expense related to the 2011 VEP has been fully recognized.

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Restricted Stock Awards

The Company granted 101,510, 103,730 and 65,390 restricted stock awards during the years ended December 31, 2013, 2012 and 2011, respectively, to key employees of the Company. The restricted shares granted will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued employment. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Company s common stock, was approximately $71, $54 and $52 for the years ended December 31, 2013, 2012 and 2011, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2013, 2012 and 2011 was $4.3 million, $1.6 million and $5.1 million, respectively.

As of December 31, 2013, $7.0 million of unrecognized compensation cost related to nonvested restricted stock awards was expected to be recognized over a remaining weighted average vesting term of approximately 1.7 years.

A summary of restricted stock activity as of December 31, 2013, and changes during the year then ended, is presented below:

Restricted Stock	Non-Vested Shares	Weighted Average Fair Value	Aggregate Fair Value

[redacted]

For the restricted stock awards that vested in 2013, 23,053 related to discontinued operations at a weighted average fair value of $56.28 and an aggregate fair value of $1.3 million. For the restricted stock awards that were forfeited in 2013, 18,357 related to discontinued operations at a weighted average fair value of $55.00 and an aggregate fair value of $1.0 million.

Non-Qualified Stock Options

The fair value of the Company s option grants was estimated at the dates of grant using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the years ended December 31, 2013, 2012 and 2011. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the date of grant. The dividend yield is based on the dividend yield of the Company s common stock at the time of grant. Expected volatilities are based on historical volatility of the Company s common stock. The expected term of options granted represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

	Years Ended December 31,		
	2013	**2012**	**2011**
Risk-free interest rate	0.76%	0.89%	2.02%
Dividend yield	0.22%	1.64%	2.19%
Volatility factor	31.69%	31.44%	28.92%
Expected term	5 years	5 years	5 years

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The Company granted 259,600, 278,300 and 229,100 stock options during the years ended December 31, 2013, 2012 and 2011, respectively. The weighted average grant date fair value of the options was $16.72, $13.19 and $10.06 for the years ended December 31, 2013, 2012 and 2011, respectively. The total intrinsic value of options exercised during the years ended December 31, 2013, 2012 and 2011 was $22.8 million, $11.8 million, and $18.3 million, respectively.

As of December 31, 2013, $2.1 million of unrecognized compensation cost related to outstanding nonvested stock options was expected to be recognized by December 31, 2014.

A summary of option activity as of December 31, 2013, and changes during the year then ended, is presented below:

Non-qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2013	1,864,375	$ 46.01		
Granted	259,600	$ 58.98		
Exercised	(637,174)	$ 42.44		
Forfeited	(4,800)	$ 58.98		
Outstanding at December 31, 2013	1,482,001	$ 49.77	4.7 years	$ 59,287,589
Exercisable at December 31, 2013	1,088,051	$ 46.98	3.3 years	$ 46,570,891

For stock options exercised in 2013, 8,100 shares related to discontinued operations at a weighted average exercise price of $24.39.

Non-employee Directors Share-Based Awards

The Company has historically granted to non-employee directors share-based awards which vest upon grant of the awards. The value of the share-based awards will be paid in cash or Company common stock upon the directors termination of service on the Company s Board of Directors. For awards which will be paid in cash, the Company accounts for these awards as liability awards and as such records compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. For awards which will be settled in Company common stock, the Company accounts for these awards as equity awards. A total of 179,639 non-employee director share-based awards including accrued dividends were outstanding as of December 31, 2013. A total of 25,500, 28,140 and 22,140 share-based awards were granted to non-employee directors during the years ended December 31, 2013, 2012 and 2011, respectively. The weighted average fair value of these grants, based on the Company s common stock price on the grant date, was $58.98, $53.47 and $44.84 for the years ended December 31, 2013, 2012 and 2011, respectively.

EQM Awards

At the closing of the Partnership s IPO in July 2012, the Company and the general partner of the Partnership granted certain key Company employees performance awards under the EQM Total Return Program representing 146,490 common units of the Partnership. The performance condition related to the performance awards will be satisfied on December 31, 2015 if the total unitholder return realized on the Partnership s common units from the date of grant is at least 10%. If the unitholder return performance condition is not achieved as of December 31, 2015, the performance condition will nonetheless be satisfied if the 10% unitholder return threshold is satisfied as of the end of any calendar quarter ending after December 31, 2015 and on or before December 31, 2017. If earned, the units are expected to be distributed in Partnership common units.

The Company accounted for the EQM Total Return Program awards as equity awards using a $20.02 grant date fair value per unit as determined using a fair value model. The model projected the unit price for Partnership common units at the ending point of the performance period. The price was generated using annual historical

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volatilities of peer group companies for the expected term of the awards, which was based upon the performance period. The range of expected volatilities calculated by the valuation model was 27% - 72%, and the weighted-average expected volatility was approximately 38%. Additional assumptions included the risk-free rate for periods within the contractual life of the awards based on the U.S. Treasury yield curve in effect at the time of grant and an expected Partnership distribution growth rate of 10%. Adjusting for 3,990 forfeitures, there were 142,500 awards outstanding as of December 31, 2013. As of December 31, 2013, $1.7 million of unrecognized compensation cost related to the EQM Total Return Program was expected to be recognized over the next two years.

Additionally, the general partner of the Partnership has granted Partnership common unit-based phantom awards to its independent directors, which vested upon grant. The value of the phantom awards will be paid in Partnership common units upon the director s termination of service on the general partner s Board of Directors. The Company accounts for these awards as equity awards and as such recorded compensation expense for the fair value of the awards at the grant date fair value. A total of 8,886 independent director unit-based awards including accrued distributions were outstanding as of December 31, 2013. A total of 3,790 and 4,780 unit-based awards were granted to independent directors during the years ended December 31, 2013 and 2012, respectively. The weighted average fair value of these grants, based on the Partnership s common unit price on the grant date, was $37.92 and $24.30 for the years ended December 31, 2013 and 2012, respectively.

2014 Value Driver Award Programs and 2014 Executive Performance Incentive Program

Effective in 2014, the Compensation Committee of the Board of Directors adopted the 2014 EQT Value Driver Award Program (2014 EQT VDA), the 2014 EQM Value Driver Program (2014 EQM VDA) and the 2014 Executive Performance Incentive Program (2014 EPIP) under the 2009 Long-Term Incentive Plan. The 2014 EQT VDA, 2014 EQM VDA and 2014 EPIP were established to align the interests of key employees with the interests of shareholders, Partnership unitholders and customers and the strategic objectives of the Company and the Partnership.

A total of 187,160 units were granted under the 2014 EQT VDA. Fifty percent of the units confirmed under the 2014 EQT VDA will vest upon the payment date following the first anniversary of the grant date; the remaining 50% of the confirmed units under the 2014 EQT VDA will vest upon the payment date following the second anniversary of the grant date. The payout will vary between zero and 300% of the number of outstanding units contingent upon adjusted 2014 EBITDA performance as compared to the Company s annual business plan and individual, business unit and Company value driver performance over the period January 1, 2014 through December 31, 2014. If earned, the 2014 EQT VDA units are expected to be paid in cash. The Company did not record any obligation or expense related to the 2014 EQT VDA as of December 31, 2013.

A total of 32,840 units were granted under the 2014 EQM VDA. Fifty percent of the units confirmed under the 2014 EQM VDA will vest upon the payment date following the first anniversary of the grant date; the remaining 50% of the confirmed units under the 2014 EQM VDA will vest upon the payment date following the second anniversary of the grant date. The payout will vary between zero and 300% of the number of outstanding units contingent upon adjusted 2014 Partnership EBITDA performance as compared to the Partnership s annual business plan and individual, business unit and Partnership value driver performance over the period January 1, 2014 through December 31, 2014. If earned, the

2014 EQM VDA units are expected to be paid in Partnership common units. The Company did not record any expense related to the 2014 EQM VDA as of December 31, 2013.

A total of 278,430 units were granted under the 2014 EPIP. The vesting of the units under the 2014 EPIP will occur upon payment after December 31, 2016 (the end of the three-year performance period). The payout will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group and the level of production sales volume growth over the period January 1, 2014 through December 31, 2016. If earned, the 2014 EPIP units are expected to be distributed in Company common stock. The Company did not record any expense related to the 2014 EPIP as of December 31, 2013.

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2014 Stock Options

Effective January 1, 2014, the Compensation Committee of the Board of Directors granted 133,500 non-qualified stock options to key employees of the Company. The 2014 options are ten-year options, with an exercise price of $89.78 and are subject to three year cliff vesting. The Company did not record any expense related to 2014 stock options as of December 31, 2013.

17. Concentrations of Credit Risk

Revenues and related accounts receivable from the EQT Production segment s operations are generated primarily from the sale of produced natural gas, NGLs and crude oil to marketers, utility and industrial customers located mainly in the Appalachian Basin and a gas processor in Kentucky and West Virginia. Additionally, a significant amount of revenues and related accounts receivable from EQT Midstream are generated from the gathering of natural gas in Kentucky, Virginia, Pennsylvania and West Virginia. The Company had one customer within the EQT Production segment account for approximately 11% of its revenues in 2013. No single customer accounted for more than 10% of revenues in 2012 or 2011.

Approximately 82% of the Company s accounts receivable balance as of December 31, 2013 and 2012, respectively, represented amounts due from marketers. The Company manages the credit risk of sales to marketers by limiting its dealings to those marketers that meet the Company s criteria for credit and liquidity strength and by regularly monitoring these accounts. The Company may require letters of credit, guarantees, performance bonds or other credit enhancements from a marketer in order for that marketer to meet the Company s credit criteria. As a result, the Company did not experience any significant defaults on sales of natural gas to marketers during the years ended December 31, 2013, 2012 or 2011.

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company believes that NYMEX-traded future contracts have limited credit risk because CFTC regulations are in place to protect exchange participants, including the Company, from any potential financial instability of the exchange members. The Company s OTC swap and collar derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those companies individually as well as that industry as a whole.

The Company utilizes various processes and analyses to monitor and evaluate its credit risk exposures. These include monitoring current market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions with financial counterparties that are of investment grade or better, enters into netting agreements whenever possible and may obtain collateral or other security.

As of December 31, 2013, the Company was not in default under any derivative contracts and has no knowledge of default by any counterparty to derivative contracts. The Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company s established fair value procedure. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

18. Commitments and Contingencies

The Company has commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines. Future payments for these items as of December 31, 2013 totaled $2,167.8 million (2014 - $140.8 million, 2015 - $192.4 million, 2016 - $184.8 million, 2017 - $180.8 million, 2018 - $180.8 million and thereafter - $1,288.2 million). The Company has entered into agreements to release some of its capacity to various third parties.

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

The Company has agreements with drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $70.4 million as of December 31, 2013. Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $56.0 million in 2013, $45.0 million in 2012 and $74.7 million in 2011. Future lease payments under non-cancelable operating leases as of December 31, 2013 totaled $134.2 million (2014 - $42.9 million, 2015 - $25.6 million, 2016 - $18.4 million, 2017 $10.7 million, 2018 - $6.3 million and thereafter - $30.3 million).

The Company is subject to various federal, state and local environmental and environmentally-related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may in certain instances result in assessment of fines. The Company has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. The estimated costs associated with identified situations that require remedial action are accrued. However, certain costs are deferred as regulatory assets when recoverable through regulated rates. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material effect on the Company s financial position, results of operations or liquidity. The Company has identified situations that require remedial action for which approximately $0.6 million is included in other liabilities and credits in the Consolidated Balance Sheets as of December 31, 2013.

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company accrues legal or other direct costs related to loss contingencies when actually incurred. The Company has established reserves it believes to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, the Company believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the financial position, results of operations or liquidity of the Company.

19. Guarantees

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees were approximately $172 million as of December 31, 2013, extending at a decreasing amount for approximately 14 years.

In exchange for the Company s agreement to maintain these guarantee obligations, the purchaser of the NORESCO business and NORESCO agreed, among other things, that NORESCO would fully perform its obligations under each underlying agreement and agreed to reimburse the Company for any loss under the guarantee obligations, provided that the purchaser s reimbursement obligation will not exceed $6 million in the aggregate and will expire on November 18, 2014. In 2008, the original purchaser of NORESCO sold its interest in NORESCO and transferred its obligations to a third party. In connection with that event, the new owner delivered to the Company a $1 million letter of credit supporting its obligations.

The NORESCO guarantees are exempt from ASC Topic 460, Guarantees. The Company has determined that the likelihood it will be required to perform on these arrangements is remote and any potential payments are expected to be immaterial to the Company s financial position, results of operations and liquidity. As such, the Company has not recorded any liabilities in its Consolidated Balance Sheets related to these guarantees.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

20. Interim Financial Information (Unaudited)

The following quarterly summary of operating results reflects variations due primarily to the volatility of natural gas commodity prices and the seasonal nature of the Company s storage business.

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(Thousands, except per share amounts)			
2013 (a)				
Operating revenues	$ 415,883	$ 473,093	$ 479,606	$ 493,429
Operating income	144,479	161,980	167,064	181,081
Amounts attributable to EQT Corporation:				
Income from continuing operations	69,131	81,466	86,199	61,933
Income from discontinued operations	31,124	5,390	2,057	53,272
Net income attributable to EQT Corporation	$ 100,255	$ 86,856	$ 88,256	$ 115,205
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
Income from continuing operations	$ 0.46	$ 0.54	$ 0.57	$ 0.41
Income from discontinued operations	0.21	0.04	0.02	0.35
Net income	$ 0.67	$ 0.58	$ 0.59	$ 0.76
Diluted:				
Income from continuing operations	$ 0.46	$ 0.54	$ 0.57	$ 0.40
Income from discontinued operations	0.20	0.03	0.01	0.35
Net income	$ 0.66	$ 0.57	$ 0.58	$ 0.75
2012 (a)				
Operating revenues	$ 334,291	$ 298,742	$ 337,916	$ 406,273
Operating income	111,054	70,817	81,253	126,505
Amounts attributable to EQT Corporation:				
Income from continuing operations	48,467	25,302	29,010	33,123
Income from discontinued operations	23,568	6,144	2,863	14,918
Net income attributable to EQT Corporation	$ 72,035	$ 31,446	$ 31,873	$ 48,041
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
Income from continuing operations	$ 0.32	$ 0.17	$ 0.19	$ 0.22
Income from discontinued operations	0.16	0.04	0.02	0.10
Net income	$ 0.48	$ 0.21	$ 0.21	$ 0.32

Diluted:								
Income from continuing operations	$	0.32	$	0.17	$	0.19	$	0.22
Income from discontinued operations		0.16		0.04		0.02		0.10
Net income	$	0.48	$	0.21	$	0.21	$	0.32

(a) The sum of the quarterly data in some cases may not equal the yearly total due to rounding.

Differences between all amounts in the above table and those previously reported in the Company s 2013 and 2012 Form 10-Qs are attributable to the Equitable Gas Transaction, as described in Note 2. All prior periods presented have been recast to reflect the presentation of discontinued operations.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

21. Natural Gas Producing Activities (Unaudited)

The supplementary information summarized below presents the results of natural gas and oil activities for the EQT Production segment in accordance with the successful efforts method of accounting for production activities.

Production Costs

The following table presents the costs incurred relating to natural gas, NGL and oil production activities (a):

	For the Years Ended December 31, 2013	2012	2011
		(Thousands)	
At December 31:			
Capitalized costs	$ 8,152,951	$ 6,750,343	$ 5,772,083
Accumulated depreciation and depletion	2,134,953	1,572,775	1,177,526
Net capitalized costs	$ 6,017,998	$ 5,177,568	$ 4,594,557
Costs incurred for the years ended December 31:			
Property acquisition:			
Proved properties (b)	$ 90,390	$ 16,965	$ 108,717
Unproved properties	95,861	117,654	41,085
Exploration (c)	4,285	4,827	2,344
Development	1,230,301	850,854	928,294

(a) Amounts exclude capital expenditures for facilities and information technology.

(b) Amounts include $57.0 million for the purchase of Marcellus wells acquired in the Chesapeake acquisition in 2013 and $92.6 million of liabilities assumed in exchange for proved developed properties as part of the ANPI transaction in 2011.

(c) Amounts include capitalizable exploratory costs and exploration expense, excluding impairments.

Results of Operations for Producing Activities

The following table presents the results of operations related to natural gas, NGL and oil production.

	For the Years Ended December 31, 2013	2012	2011
		(Thousands)	
Revenues:			
Affiliated	$ 5,912	$ 3,433	$ 6,225
Nonaffiliated	1,162,745	790,340	785,060
Production costs	108,091	96,155	80,911
Exploration costs	18,483	10,370	4,932
Depreciation, depletion and accretion	578,641	409,628	257,144
Income tax expense	183,060	109,660	174,835
Results of operations from producing activities (excluding corporate overhead)	$ 280,382	$ 167,960	$ 273,463

Reserve Information

The information presented below represents estimates of proved natural gas, NGL and oil reserves prepared by Company engineers. The engineer primarily responsible for preparing the reserve report and the technical aspects of the reserves audit received a bachelor s degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University and has 25 years of experience in the oil and gas industry. To ensure that the reserves are materially accurate, management reviews the price, heat content conversion rate and cost assumptions used in the economic model to determine the reserves; division of interest and production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems; the reserve reconciliation

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

between prior year reserves and current year reserves is reviewed by senior management; and the estimates of proved natural gas, NGL and oil reserves are audited by the independent consulting firm of Ryder Scott Company, L.P. (Ryder Scott), which is hired by the Company s management. Since 1937, Ryder Scott has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally.

Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. There were no differences between the internally prepared and externally audited estimates. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells after substantial development costs are incurred. Ryder Scott reviewed 100% of the total net gas, NGL and oil proved reserves attributable to the Company s interests as of December 31, 2013. Ryder Scott conducted a detailed, well by well, audit of the Company s largest properties. This audit covered 80% of the Company s proved reserves. Ryder Scott s audit of the remaining 20% of the Company s properties consisted of an audit of aggregated groups not exceeding 200 wells per group. The audit utilized the performance method and the analogy method. Where historical reserve or production data was definitive, the performance method, which extrapolates historical data, was utilized. In other cases the analogy method, which calculates reserves based on correlations to comparable surrounding wells, was utilized. All of the Company s proved reserves are located in the United States.

	Years Ended December 31,		
	2013	2012	2011
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	5,985,758	5,347,386	5,205,692
Revision of previous estimates	(375,887)	(755,788)	(393,129)
Purchase of natural gas in place	472,798		39,436
Sale of natural gas in place	(455)	(694)	(1,223)
Extensions, discoveries and other additions	1,844,840	1,654,228	694,180
Production	(365,493)	(259,374)	(197,570)
End of year	7,561,561	5,985,758	5,347,386
Proved developed reserves:			
Beginning of year	2,779,187	2,948,546	2,520,569
End of year	3,567,313	2,779,187	2,948,546

	Years Ended December 31,		
	2013	2012	2011
	(Thousands of Bbls)		
Oil (a)			
Proved developed and undeveloped reserves:			
Beginning of year	3,199	2,931	2,307
Revision of previous estimates	270	265	781
Purchase of oil in place			51

Sale of oil in place			
Extensions, discoveries and other additions	757	268	
Production	(270)	(265)	(208)
End of year	3,956	3,199	2,931
Proved developed reserves:			
Beginning of year	3,199	2,931	2,307
End of year	3,892	3,199	2,931

(a) One thousand Bbl equals approximately 6 million cubic feet (MMcf).

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

NGLs (a)	**Year Ended December 31, 2013 (Thousands of Bbls)**
Proved developed and undeveloped reserves:	
Beginning of year	
Revision of previous estimates	94,296
Purchase of NGLs in place	
Sale of NGLs in place	
Extensions, discoveries and other additions	32,866
Production	
End of year	127,162
Proved developed reserves:	
Beginning of year	
End of year	65,837

(a) One thousand Bbl equals approximately 6 million cubic feet (MMcf).

As discussed in Note 8, the Company acquired the Class A interest in ANGT in May 2011. Prior to this acquisition, the Company held a 1% equity interest in ANGT which was accounted for under the equity method. The Company s share of these reserves and the impact on the standard measure of discounted future cash flow was not considered material and therefore was excluded from these measures prior to the acquisition. This acquisition added 39.7 Bcfe of proved developed reserves.

During 2013, the Company recorded upward revisions of 191.5 Bcfe to the December 31, 2012 estimates of its reserves primarily due to the increase in the average NYMEX natural gas price for the year causing the properties to remain economic for a longer period. This increase was partially offset by negative revisions of 349 Bcfe, which was primarily due to the removal of 58 undeveloped locations and their associated reserves. The Company has included NGL reserves for the first time in 2013. This caused a one-time decrease in gas reserves and an increase in equivalent reserves. Due to the continued growth in NGL reserves, the Company is separately calculating and presenting such reserves. The Company s 2013 extensions, discoveries and other additions, resulting from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery, of 2,046.6 Bcfe exceeded the 2013 production of 367.1 Bcfe. These reserve extensions and discoveries were mainly due to decreased lateral spacing in one of the Company s locations in Greene County, Pennsylvania, and additional proved locations in the Company s Pennsylvania and West Virginia Marcellus fields and the addition of Huron proved undeveloped reserves due to the re-establishment of the Huron development program.

During 2012, the Company recorded downward revisions of 754.2 Bcfe to the December 31, 2011 estimates of its reserves primarily due to the decrease in the average NYMEX natural gas price for the year causing the existing reserves to become uneconomic in accordance with SEC pricing requirements. The Company s 2012 extensions, discoveries and other additions, resulting from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery, of 1,655.8 Bcfe exceeded the 2012 production of 261.0 Bcfe. These reserve extensions and discoveries were mainly due to decreased lateral spacing in one of the Company s Greene County, Pennsylvania locations and additional proved locations in the Company s Wetzel and Doddridge County, West Virginia development areas.

During 2011, the Company recorded downward revisions of 388.4 Bcfe to the December 31, 2010 estimates of its reserves primarily due to removing proved undeveloped reserves in the Huron play in order to focus capital and resources in the Marcellus play over the five-year time horizon included in the proved undeveloped reserves development plan. The Company s 2011 extensions, discoveries and other additions, resulting from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery of 694.2 Bcfe exceeded the 2011 production of 198.8 Bcfe.

As of December 31, 2013, the Company did not have any reserves that have been classified as proved undeveloped reserves for more than five years.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

Standard Measure of Discounted Future Cash Flow

Management cautions that the standard measure of discounted future cash flows should not be viewed as an indication of the fair market value of natural gas and oil producing properties, nor of the future cash flows expected to be generated therefrom. The information presented does not give recognition to future changes in estimated reserves, selling prices or costs and has been discounted at a rate of 10%.

Estimated future net cash flows from natural gas and oil reserves are as follows at December 31:

	2013	2012	2011
		(Thousands)	
Future cash inflows (a)	$ 25,912,542	$ 15,250,019	$ 22,145,953
Future production costs	(4,180,136)	(3,070,957)	(3,435,200)
Future development costs	(4,199,722)	(3,082,053)	(2,600,982)
Future income tax expenses	(6,533,817)	(3,324,472)	(6,075,539)
Future net cash flow	10,998,867	5,772,537	10,034,232
10% annual discount for estimated timing of cash flows	(7,047,588)	(3,617,378)	(6,101,408)
Standardized measure of discounted future net cash flows	$ 3,951,279	$ 2,155,159	$ 3,932,824

(a) The majority of the Company s production is sold through liquid trading points on interstate pipelines. For 2013, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2013 of $89.22 per Bbl of oil (first day of each month closing price for WTI less Appalachian Basin adjustment), $3.653 per Dth for Columbia Gas Transmission Corp., $3.447 per Dth for Dominion Transmission, Inc., $3.693 per Dth for the East Tennessee Natural Gas Pipeline, $3.495 per Dth for Texas Eastern Transmission Corp., $2.842 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company and $3.521 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company.

For 2012, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2012 of $82.90 per Bbl of oil (first day of each month closing price for WTI less Appalachian Basin adjustment), $2.793 per Dth for Columbia Gas Transmission Corp., $2.785 per Dth for Dominion Transmission, Inc., $2.769 per Dth for the East Tennessee Natural Gas Pipeline, $2.782 per Dth for Texas Eastern Transmission Corp., $2.403 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company and $2.878 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company. For 2012, the West Virginia Marcellus reserves from Doddridge and Ritchie Counties were computed using an additional $0.591 and reserves from Wetzel County were computed using an additional $0.398 for revenues earned on NGLs that are produced from those reserves. Revenues earned on NGLs that are produced from certain Kentucky reserves were computed using an additional $0.764.

For 2011, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2011 of $92.84 per Bbl of oil (first day of each month closing price for WTI less Appalachian Basin adjustment), $4.198 per Dth for Columbia Gas Transmission Corp., $4.243 per Dth for Dominion Transmission, Inc., $4.159 per Dth for the East Tennessee Natural Gas Pipeline and $4.172 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company. The Company sold Langley on February 1, 2011. As a result of that sale, management determined that the revenue received from the fractionation of

NGLs which were extracted from the Company s produced natural gas would be reported in EQT Production rather than EQT Midstream. For 2011, the West Virginia Marcellus reserves and certain Kentucky reserves were computed using an additional \$1.139 and \$2.149, respectively, for revenues earned on NGLs that are produced from those reserves.

Holding production and development costs constant, a change in price of \$1 per Dth for natural gas and \$10 per barrel for oil would result in a change in the December 31, 2013 discounted future net cash flows before income taxes of the Company s proved reserves of approximately \$3.2 billion and \$15.6 million, respectively.

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EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2013 (Continued)

Summary of changes in the standardized measure of discounted future net cash flows for the years ended December 31:

	2013	2012	2011
		(Thousands)	
Sales and transfers of natural gas and oil produced net	$ (1,060,566)	$ (697,618)	$ (710,373)
Net changes in prices, production and development costs	(292,533)	(3,530,086)	52,057
Extensions, discoveries and improved recovery, less related costs	1,509,002	917,986	806,597
Development costs incurred	1,319,135	548,852	498,175
Purchase of minerals in place net	348,608		46,178
Sale of minerals in place net	(252)	(807)	(1,124)
Revisions of previous quantity estimates	106,170	(876,336)	(356,830)
Accretion of discount	343,502	622,072	478,165
Net change in income taxes	(1,031,105)	1,127,272	(560,360)
Timing and other	554,159	111,000	622,127
Net increase (decrease)	1,796,120	(1,777,665)	874,612
Beginning of year	2,155,159	3,932,824	3,058,212
End of year	$ 3,951,279	$ 2,155,159	$ 3,932,824

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not Applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including the Company s Principal Executive Officer and Principal Financial Officer, an evaluation of the Company s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), was conducted as of the end of the period covered by this report. Based on that evaluation, the Principal Executive Officer and Principal Financial Officer concluded that the Company s disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Management s Report on Internal Control over Financial Reporting

The management of EQT is responsible for establishing and maintaining adequate internal control over financial reporting. EQT s internal control system is designed to provide reasonable assurance to the Company s management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Accordingly, even effective controls can provide only reasonable assurance with respect to financial statement preparation and presentation.

EQT s management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework* (1992). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2013.

Ernst & Young LLP (Ernst & Young), the independent registered public accounting firm that audited the Company s Consolidated Financial Statements, has issued an attestation report on the Company s internal control over financial reporting. Ernst & Young s attestation report on the Company s internal control over financial reporting appears in Part II, Item 8 of this Annual Report on Form 10-K and is incorporated by reference herein.

Item 9B. Other Information

Not Applicable.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated herein by reference from the Company s definitive proxy statement relating to the annual meeting of the shareholders to be held on April 30, 2014, which proxy statement will be filed with the SEC within 120 days after the close of the Company s fiscal year ended December 31, 2013:

- Information required by Item 401 of Regulation S-K with respect to directors is incorporated herein by reference from the sections captioned Item No. 1 Election of Directors, Nominees to Serve for a One-Year Term Expiring in 2015, Other Directors Whose Terms Expire in 2015, Directors Whose Terms Expire in 2016 and Corporate Governance and Board Matters in the Company s definitive proxy statement;

- Information required by Item 405 of Regulation S-K with respect to compliance with Section 16(a) of the Exchange Act is incorporated herein by reference from the section captioned Equity Ownership Section 16(a) Beneficial Ownership Reporting Compliance in the Company s definitive proxy statement;

- Information required by Item 407(d)(4) of Regulation S-K with respect to disclosure of the existence of the Company s separately-designated standing Audit Committee and the identification of the members of the Audit Committee is incorporated herein by reference from the section captioned Corporate Governance and Board Matters Board Meetings and Committees Audit Committee in the Company s definitive proxy statement; and

- Information required by Item 407(d)(5) of Regulation S-K with respect to disclosure of the Company s audit committee financial expert is incorporated herein by reference from the section captioned Corporate Governance and Board Matters Board Meetings and Committees Audit Committee in the Company s definitive proxy statement.

Information required by Item 401 of Regulation S-K with respect to executive officers is included after Item 4 at the end of Part I of this Form 10-K under the caption Executive Officers of the Registrant (as of February 20, 2014), and is incorporated herein by reference.

The Company has adopted a code of ethics applicable to all directors and employees, including the principal executive officer, principal financial officer and principal accounting officer. The code of ethics is posted on the Company s website, http://www.eqt.com (accessible under the Corporate Governance caption of the Investors page), and a printed copy will be delivered free of charge on request by writing to the corporate secretary at EQT Corporation, c/o Corporate Secretary, 625 Liberty Avenue, Suite 1700, Pittsburgh, Pennsylvania 15222. The Company intends to satisfy the disclosure requirement regarding certain amendments to, or waivers from, provisions of its code of ethics by posting such information on the Company s website.

Item 11. Executive Compensation

The following information is incorporated herein by reference from the Company s definitive proxy statement relating to the annual meeting of the shareholders to be held on April 30, 2014, which proxy statement will be filed with the SEC within 120 days after the close of the Company s fiscal year ended December 31, 2013:

- Information required by Item 402 of Regulation S-K with respect to executive and director compensation is incorporated herein by reference from the sections captioned Corporate Governance and Board Matters Compensation Policies and Practices and Risk Management, Directors Compensation and Executive Compensation in the Company s definitive proxy statement; and

- Information required by paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K with respect to certain matters related to the Management Development and Compensation Committee is incorporated herein by reference from the sections captioned Corporate Governance and Board Matters Compensation

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Committee Interlocks and Insider Participation and Report of the Management Development and Compensation Committee in the Company s definitive proxy statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following information is incorporated herein by reference from the Company s definitive proxy statement relating to the annual meeting of the shareholders to be held on April 30, 2014, which proxy statement will be filed with the SEC within 120 days after the close of the Company s fiscal year ended December 31, 2013:

- Information required by Item 201(d) of Regulation S-K with respect to equity compensation plan information is incorporated herein by reference from the section captioned Equity Compensation Plan Information in the Company s definitive proxy statement; and

- Information required by Item 403 of Regulation S-K with respect to stock ownership of significant shareholders, directors and executive officers is incorporated herein by reference from the sections captioned Equity Ownership Stock Ownership of Significant Shareholders and Equity Ownership Equity Ownership of Directors and Executive Officers in the Company s definitive proxy statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by Items 404 and 407(a) of Regulation S-K with respect to director independence and related person transactions is incorporated herein by reference to the sections captioned Corporate Governance and Board Matters Independence and Related Person Transactions in the Company s definitive proxy statement relating to the annual meeting of shareholders to be held on April 30, 2014, which proxy statement will be filed with the SEC within 120 days after the close of the Company s fiscal year ended December 31, 2013.

Item 14. Principal Accounting Fees and Services

Information required by Item 9(e) of Schedule 14A is incorporated herein by reference to the section captioned Item No. 5 Ratification of Appointment of Independent Registered Public Accounting Firm in the Company s definitive proxy statement relating to the annual meeting of stockholders to be held on April 30, 2014, which proxy statement will be filed with the SEC within 120 days after the close of the Company s fiscal year ended December 31, 2013.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements
The financial statements listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

2. Financial Statement Schedule
The financial statement schedule listed in the accompanying index to financial statements and financial schedule is filed as part of this Annual Report on Form 10-K.

3. Exhibits
The exhibits listed on the accompanying index to exhibits (pages 118 through 125) are filed as part of this Annual Report on Form 10-K.

EQT CORPORATION

INDEX TO FINANCIAL STATEMENTS COVERED

BY REPORT OF INDEPENDENT REGISTERED

PUBLIC ACCOUNTING FIRM

1. The following Consolidated Financial Statements of EQT Corporation and Subsidiaries are included in Item 8:

2. Schedule for the Three Years Ended December 31, 2013 included in Part IV:

All other schedules are omitted since the subject matter thereof is either not present or is not present in amounts sufficient to require submission of the schedules.

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EQT CORPORATION AND SUBSIDIARIES

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

FOR THE THREE YEARS ENDED DECEMBER 31, 2013

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	(Deductions) Additions Charged to Costs and Expenses	Additions Charged to Other Accounts (Thousands)	Deductions (a)	Balance at End of Period
Allowance for doubtful accounts:					
2013	$ 5,883	$ (704)	$	$ 8	$ 5,171
2012	$ 7,626	$ (1,637)	$	$ 106	$ 5,883
2011	$ 7,324	$ 327	$	$ 25	$ 7,626

Note:

(a) Amount represents customer accounts written off, less recoveries.

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INDEX TO EXHIBITS

[redacted]

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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INDEX TO EXHIBITS

[redacted]

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INDEX TO EXHIBITS

[redacted]

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INDEX TO EXHIBITS

[redacted]

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INDEX TO EXHIBITS

[redacted]

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.08	2005 Directors Deferred Compensation Plan (as amended and restated December 2, 2009)	Filed as Exhibit 10.06 to Form 10-K for the year ended December 31, 2009
* 10.09(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and David L. Porges	Filed as Exhibit 10.8 to Form 10-Q for the quarter ended September 30, 2008
* 10.09(b)	Amendment to Confidentiality, Non-Solicitation and Non-Competition Agreement effective as of January 1, 2014 between the Company and David L. Porges	Filed herewith as Exhibit 10.09(b)
* 10.09(c)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and David L. Porges	Filed as Exhibit 10.10(b) to Form 10-K for the year ended December 31, 2012
* 10.10(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Philip P. Conti	Filed as Exhibit 10.10 to Form 10-Q for the quarter ended September 30, 2008
* 10.10(b)	Amendment to Confidentiality, Non-Solicitation and Non-Competition Agreement effective as of January 1, 2014 between the Company and Philip P. Conti	Filed herewith as Exhibit 10.10(b)
* 10.10(c)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Philip P. Conti	Filed as Exhibit 10.11(b) to Form 10-K for the year ended December 31, 2012
* 10.11(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Randall L. Crawford	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2013
* 10.11(b)	Amendment to Confidentiality, Non-Solicitation and Non-Competition Agreement effective as of January 1, 2014 between the Company and Randall L. Crawford	Filed herewith as Exhibit 10.11(b)
* 10.11(c)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Randall L. Crawford	Filed as Exhibit 10.12(b) to Form 10-K for the year ended December 31, 2012
* 10.12(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Lewis B. Gardner	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2013

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.12(b)	Amendment to Confidentiality, Non-Solicitation and Non-Competition Agreement effective as of January 1, 2014 between the Company and Lewis B. Gardner	Filed herewith as Exhibit 10.12(b)
* 10.12(c)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Lewis B. Gardner	Filed as Exhibit 10.13(b) to Form 10-K for the year ended December 31, 2012
* 10.13(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Steven T. Schlotterbeck	Filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2013
* 10.13(b)	Amendment to Confidentiality, Non-Solicitation and Non-Competition Agreement effective as of January 1, 2014 between the Company and Steven T. Schlotterbeck	Filed herewith as Exhibit 10.13(b)
* 10.13(c)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Steven T. Schlotterbeck	Filed as Exhibit 10.14(b) to Form 10-K for the year ended December 31, 2012
* 10.14	Form of Indemnification Agreement between the Company and each executive officer and each outside director	Filed as Exhibit 10.18 to Form 10-K for the year ended December 31, 2008
10.15	Amended and Restated Revolving Credit Agreement dated as of February 18, 2014 among the Company, PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Wells Fargo Bank, National Association, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Bank of America, N.A., Barclays Bank PLC, Citibank, N.A., JPMorgan Chase Bank, N.A. and SunTrust Bank, as Syndication Agents, and the other lender parties thereto	Filed as Exhibit 10.1 to Form 8-K filed on February 18, 2014
21	Schedule of Subsidiaries	Filed herewith as Exhibit 21
23.01	Consent of Independent Registered Public Accounting Firm	Filed herewith as Exhibit 23.01
23.02	Consent of Independent Petroleum Engineers	Filed herewith as Exhibit 23.02
31.01	Rule 13(a)-14(a) Certification of Principal Executive Officer	Filed herewith as Exhibit 31.01
31.02	Rule 13(a)-14(a) Certification of Principal Financial Officer	Filed herewith as Exhibit 31.02

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INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
32	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	Furnished herewith as Exhibit 32
99.01	Independent Petroleum Engineers Audit Report	Filed herewith as Exhibit 99.01
101	Interactive Data File	Filed herewith as Exhibit 101

The Company agrees to furnish to the SEC, upon request, copies of instruments with respect to long-term debt, which have not previously been filed.

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SIGNATURES

Pursuant to the requirements of Section 13 or 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.

EQT CORPORATION

By: /s/ DAVID L. PORGES
David L. Porges
Chairman, President and Chief Executive Officer
February 20, 2014

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.

/s/ DAVID L. PORGES David L. Porges (Principal Executive Officer)	Chairman, President, Chief Executive Officer, and Director	February 20, 2014
/s/ PHILIP P. CONTI Philip P. Conti (Principal Financial Officer)	Senior Vice President and Chief Financial Officer	February 20, 2014
/s/ THERESA Z. BONE Theresa Z. Bone (Principal Accounting Officer)	Vice President, Finance and Chief Accounting Officer	February 20, 2014
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 20, 2014
/s/ PHILIP G. BEHRMAN Philip G. Behrman	Director	February 20, 2014
/s/ KENNETH M. BURKE Kenneth M. Burke	Director	February 20, 2014
/s/ A. BRAY CARY JR. A. Bray Cary, Jr.	Director	February 20, 2014
/s/ MARGARET K. DORMAN Margaret K. Dorman	Director	February 20, 2014
/s/ GEORGE L. MILES, JR. George L. Miles, Jr.	Director	February 20, 2014
/s/ JAMES E. ROHR James E. Rohr	Director	February 20, 2014

/s/ DAVID S. SHAPIRA David S. Shapira	Director	February 20, 2014
/s/ STEPHEN A. THORINGTON Stephen A. Thorington	Director	February 20, 2014
/s/ LEE T. TODD, JR. Lee T. Todd, Jr.	Director	February 20, 2014