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, 2012

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

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. [X]

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_	Accelerated filer ___
Non-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, 2012: $8.0 billion

The number of shares of common stock outstanding
as of January 31, 2013: 150,347,211

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held April 17, 2013) will be filed with the Commission within 120 days after the close of the Company's fiscal year ended December 31, 2012 and is incorporated by reference in Part III to the extent described therein.

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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 comprised of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie in the Appalachian Mountains.

basis – when referring to natural gas, 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.

cash flow hedge – a derivative instrument that is used to reduce the exposure to variability in cash flows from the forecasted underlying transaction whereby the gains (losses) on the derivative are anticipated to offset the losses (gains) on the forecasted underlying transaction.

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.

farm tap – natural gas supply service in which the customer is served directly from a well or a gathering pipeline.

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.

heating degree days – measure used to assess weather's impact on natural gas usage calculated by adding the difference between 65 degrees Fahrenheit and the average temperature of each day in the period (if less than 65 degrees Fahrenheit). Each degree of temperature by which the average temperature falls below 65 degrees Fahrenheit represents one heating degree day. For example, a day with an average temperature of 50 degrees Fahrenheit will have 15 heating degree days.

Glossary of Commonly Used Terms, Abbreviations and Measurements

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 futures contract to guarantee fulfillment of contract obligations.

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, ethane and iso-butane.

net – "net" 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 royalty interests (equal to 100% minus all royalties on a well or property).

proved reserves – 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.

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, 1/6 or 1/4.

throughput – total volumes of natural gas sold or transported by an entity.

transportation – moving gas through pipelines on a contract basis for others.

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.

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
KY PSC – Kentucky Public Service Commission
NYMEX – New York Mercantile Exchange
OTC – over the counter
PA PUC – Pennsylvania Public Utility Commission
SEC – Securities and Exchange Commission
WV PSC – West Virginia Public Service 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 oil being equivalent to 6,000 cubic feet of gas
Dth = million British thermal units
Mcf = thousand cubic feet
Mcfe = thousand cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas
Mgal = thousand gallons
Mbbl = thousand barrels
MMBtu = million British thermal units
MMcf = million cubic feet
MMcfe = million cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas
Tcfe = trillion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas

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,” “may,” “forecast,” “approximate,” “expect,” “project,” “intend,” “plan,” “believe” and other words of similar meaning in connection with any discussion of future operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report include the matters discussed in the sections captioned “Strategy” in “Business” and “Outlook” in “Management’s Discussion 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 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 and the Company’s ability to pool lease acreage; production and sales volumes and growth rates; gathering and transmission growth and volumes (including the subscription of additional capacity related to the expiration of Equitrans, LP firm transportation contracts); infrastructure programs (including the transmission and gathering expansion projects); technology (including drilling techniques); monetization transactions, including midstream asset sales (dropdowns) to EQT Midstream Partners, LP, the Company’s publicly-traded master limited partnership formed in 2012 (the Partnership) and other asset sales, the proposed transfer of Equitable Gas Company, LLC (Equitable Gas) to PNG Companies LLC, joint ventures or other transactions involving the Company’s assets); the timing of receipt of required approvals for the proposed Equitable Gas transaction; natural gas prices; reserves; capital expenditures, including funding sources and availability; financing requirements and availability; hedging strategy; the effects of government regulation and pending and future litigation; and tax position. The forward-looking statements 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. With respect to the proposed Equitable Gas transaction, these risks and uncertainties include, among others, the ability to obtain regulatory approvals for the transaction on the proposed terms and schedule; disruption to the Company’s business, including customer, employee and supplier relationships resulting from the transaction; and risks that the conditions to closing may not be satisfied. 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 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 as of the date they were made or at any other time.

PART I

Item 1. Business

General

EQT Corporation (EQT or the Company) conducts its business through three business segments: EQT Production, EQT Midstream and Distribution. EQT Production is one of the largest natural gas producers in the Appalachian Basin with 6.0 Tcfe of proved natural gas and crude oil reserves across approximately 3.5 million gross acres, including approximately 540,000 gross acres in the Marcellus play, as of December 31, 2012. 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. The Distribution segment distributes and sells natural gas to residential, commercial and industrial customers through the Company's regulated distribution subsidiary, Equitable Gas Company, LLC (Equitable Gas). As a local distribution company, Equitable Gas has customers in southwestern Pennsylvania, West Virginia and eastern Kentucky. Equitable Gas also operates a small gathering system in Pennsylvania, and provides off-system sales activities that include the purchase and delivery of natural gas.

Key Events in 2012

In January 2012, EQT announced it would indefinitely suspend development of its Huron assets in favor of investing in its higher return Marcellus play. The decision was based on lower commodity pricing of natural gas, which resulted in a reduction in projected cash flow. A similar decision was made in December 2010, when the Company suspended the development of its CBM play in Virginia. The Company includes only proved developed reserves in these fields in its determination of proved reserves. The Company expects to continue to produce from existing wells in the Huron and CBM plays; however, contributions to the Company's total production sales volumes will gradually decline as the Company focuses the majority of its future drilling program in the Marcellus play. The Huron and CBM plays accounted for approximately 42% of production sales volumes in 2012 and are expected to account for approximately 27% of production sales volumes in 2013.

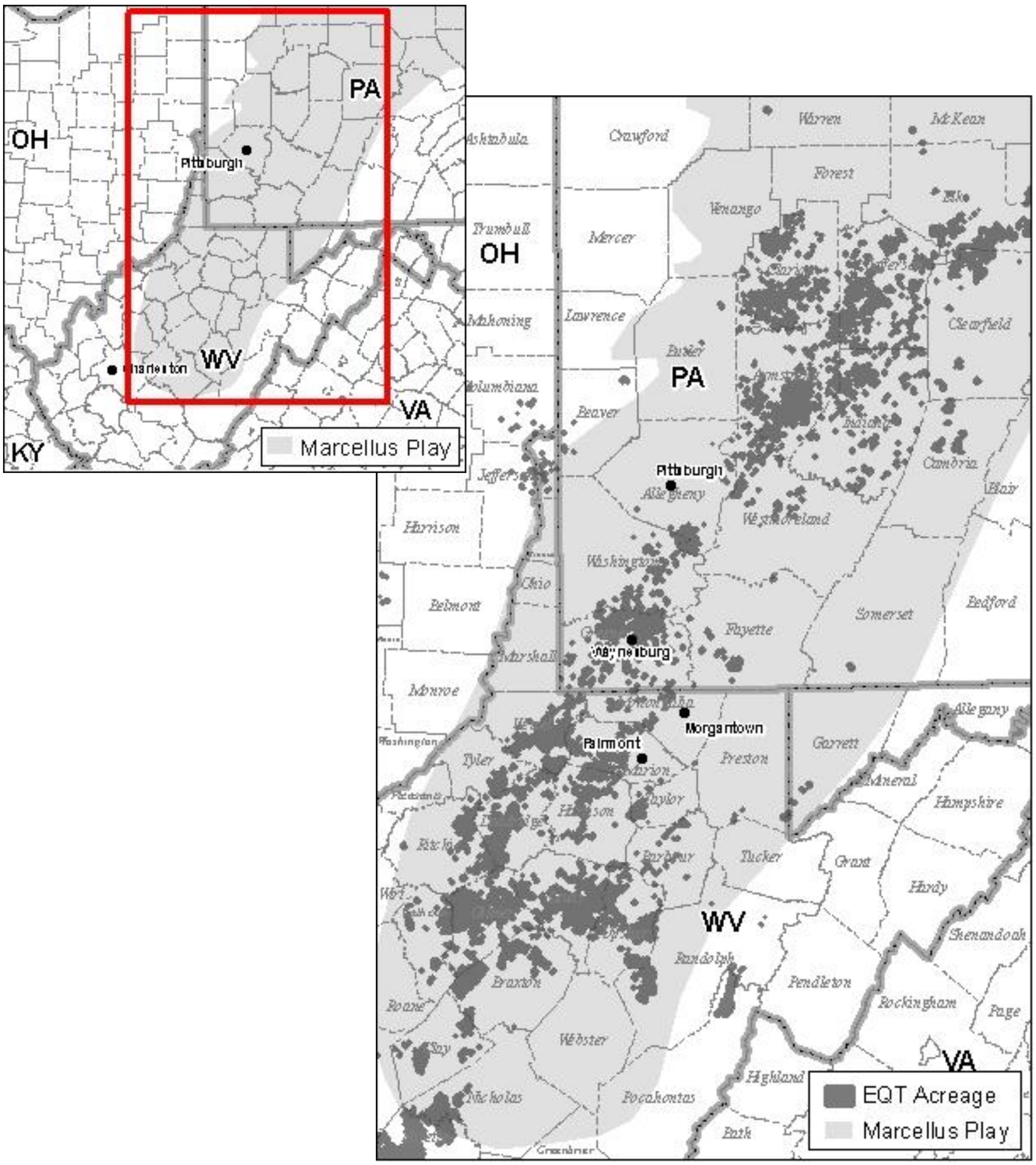
On February 13, 2012, EQT filed a registration statement with the SEC for an IPO of common units in a master limited partnership known as EQT Midstream Partners, LP (the Partnership). EQT pursued this strategy as a means of raising capital to further enhance and accelerate its economically attractive drilling and development programs, as well as to provide EQT Midstream with capital to continue pursuing additional opportunities. On July 2, 2012, the Partnership completed its underwritten IPO of 14,375,000 common units at $21.00 per unit (NYSE: EQM). EQT received net cash proceeds of approximately $231 million upon closing of the IPO, and retained a 57.4% limited partner interest and a 2% general partner interest in the Partnership. Prior to the IPO, the Company contributed to the Partnership 100% of Equitrans, LP (Equitrans), the Company's FERC-regulated transmission, storage and gathering subsidiary. An indirect wholly-owned subsidiary of EQT serves as the general partner of the Partnership and the Company continues to operate the Equitrans business pursuant to contractual arrangements signed in conjunction with the IPO. EQT records the non-controlling interest of the public limited partners in EQT's financial statements.

On December 19, 2012, EQT and its direct wholly-owned subsidiary, Distribution Holdco, LLC (Holdco), executed a Master Purchase Agreement with PNG Companies LLC (PNG Companies), the parent company of Peoples Natural Gas Company LLC (Peoples), to transfer 100% ownership of Equitable Gas and Equitable Homeworks, LLC (Homeworks) to PNG Companies. As part of the transfer, EQT will receive cash proceeds of $720 million, subject to adjustment, select midstream assets and commercial arrangements with PNG Companies and its affiliates. Homeworks and Equitable Gas are direct wholly-owned subsidiaries of Holdco. Peoples is a portfolio company of SteelRiver Infrastructure Partners. The transaction is subject to various conditions, including receipt of the approval of the PA PUC, the WV PSC, the KY PSC and the FERC. The transaction is also subject to review under the Hart-Scott-Rodino Antitrust Improvement Act. The agreements provide that such approvals and review must be complete by December 19, 2013, subject to certain extension rights. These approvals and review may not be received or completed within the time allowed.

EQT Production Business Segment

EQT believes that it is a technology leader in extended lateral horizontal drilling in the Appalachian Basin and continues to improve its operations through the use of new drilling and completion technology which increases lateral length drilled and reserves per foot of pay. The Company's strategy is to maximize value by maintaining an industry leading cost structure and profitably developing its undeveloped Marcellus reserves. EQT's proved reserves increased by 12% in 2012, to a total of 6.0 Tcfe primarily across the Marcellus and Huron shale plays, and including CBM and other vertical wells. The Company's Marcellus assets contribute approximately 4.3 Tcfe in total proved reserves.

The following illustrations depict the southwestern portion of the Marcellus Shale formation (top left), while the larger map highlights EQT's acreage position within the Marcellus:



As of December 31, 2012, the Company's proved reserves are as follows:

(Bcfe)	Marcellus	Huron *	CBM	Total
Proved Developed	1,072	1,585	141	2,798
Proved Undeveloped	3,206	–	–	3,206
Total Proved Reserves	4,278	1,585	141	6,004

* Includes the Lower Huron, Cleveland, Berea sandstone and other Devonian age formations. Also included in the Huron play is 620 Bcfe of reserves from non-shale formations accessed through vertical wells.

The Company's natural gas wells are generally low-risk with long lives and low development and production costs. Assuming that future annual production from these reserves is consistent with 2012, the remaining reserve life of the Company's total proved reserves as calculated by dividing total proved reserves by 2012 produced volumes is 23 years.

The Company invested approximately $857 million on well development in 2012 and production sales volumes increased 33% compared to 2011. Capital spending for EQT Production is expected to be approximately $1.15 billion in 2013, the majority of which will be used to support the drilling of approximately 172 gross wells, including 153 Marcellus wells, 11 Upper Devonian wells and eight wells in the Utica Shale of Ohio. Production sales volumes are expected to be approximately 31% higher for 2013, with a range expected between 335 and 340 Bcfe, including 3,900 – 4,000 Mbbls of NGL production. Over the past three years, the Company's wells drilled and related capital expenditures for well development were:

	Years Ended December 31,		
Gross wells drilled:	**2012**	**2011**	**2010**
Horizontal Marcellus	127	105	90
Horizontal Huron	7	115	236
Horizontal Utica	1	–	–
Total horizontal	135	220	326
Other	–	2	163
Total	135	222	489

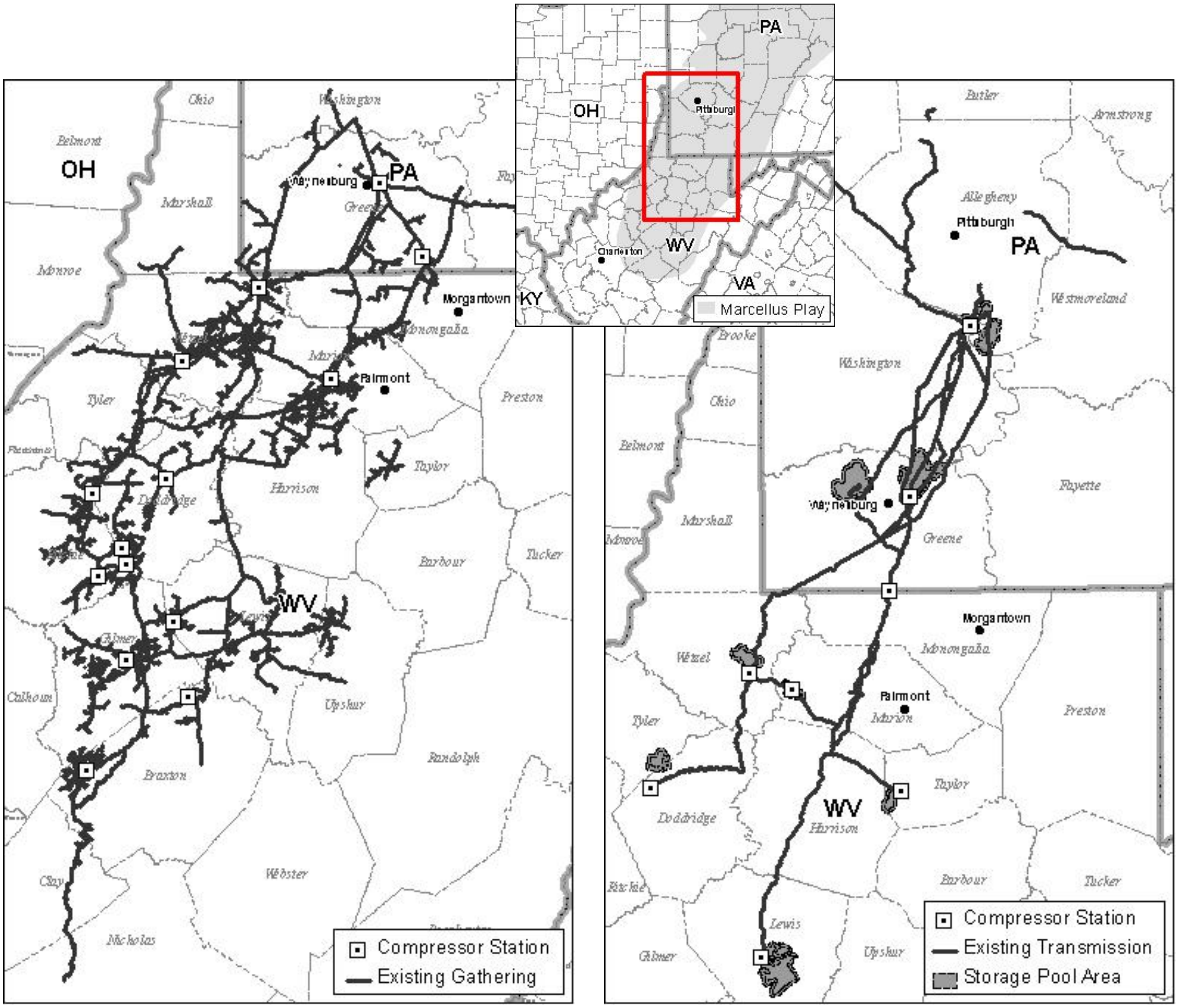
Capital expenditures for well development: (in millions):			
Horizontal Marcellus	$ 810	$ 686	$ 436
Horizontal Huron	22	226	346
Horizontal Utica	4	–	–
Total horizontal	836	912	782
Other	21	26	106
Total	$ 857	$ 938	$ 888

EQT Midstream Business Segment

During 2012, the Company completed various gathering line expansion projects and had a year-end gathering capacity of 1,115 MMcf per day, an increase of approximately 455 MMcf per day from 2011. With approximately 10,300 miles of gathering lines, EQT has Marcellus gathering capacity of 765 MMcf per day in Pennsylvania and 350 MMcf per day in West Virginia. To support the growth of production in the Marcellus play, EQT Midstream plans to add approximately 400 MMcf per day of incremental gathering capacity in 2013, all in Pennsylvania. See the map below (left) for a depiction of EQT’s gathering lines, and compressor stations, in relationship to the overall Marcellus Shale formation.

The Company’s transmission and storage system includes a FERC-regulated interstate pipeline system of approximately 700 miles that connects to five interstate pipelines and multiple distribution companies and is supported by 14 associated natural gas storage reservoirs with approximately 400 MMcf per day of peak delivery capability and 32 Bcf of working gas capacity. The map below (right) is a depiction of EQT’s transmission lines, storage pools and compressor stations in relationship to the overall Marcellus Shale formation. Equitrans includes, among other things, the 2010 Marcellus Expansion Project completed in December 2010 and the Sunrise Pipeline which Equitrans operates under a lease from an EQT affiliate. EQT’s storage reservoirs are clustered in two geographic areas connected to its Equitrans pipeline, with eight in northern West Virginia and six in southwestern Pennsylvania. During 2012, the Company completed construction of the Sunrise Pipeline, Blacksville compressor station and Braden Run interconnect projects resulting in 700 MMcf per day of increased transmission capacity. During 2013, EQT Midstream expects to add approximately 450 MMcf per day of incremental transmission capacity through the Morris III interconnect expansion and the Low Pressure East uprate projects for a total of 2,150 MMcf per day by the end of 2013.

In 2012, the Partnership was formed by EQT Corporation to own, operate, acquire and develop midstream assets in the Appalachian Basin. The Partnership provides midstream services to EQT and other third-party companies through its two primary assets: its transmission and storage system and its gathering system. The Partnership owns the approximately 700 mile FERC-regulated, interstate pipeline system, as well as approximately 2,000 miles of FERC-regulated, low-pressure gathering lines. EQT retained a 57.4% limited partner interest and a 2% general partner interest in the Partnership, whose results are consolidated in the Company's financial results.



EQT also has a gas marketing subsidiary, EQT Energy, LLC (EQT Energy), which provides optimization of capacity and storage assets, NGL sales and gas sales to commercial and industrial customers within its operational footprint through 4.9 Bcf of leased storage-related assets and approximately 1,100,000 Dth per day of third-party contractual pipeline capacity.

Strategy

EQT's strategy is to maximize shareholder value by maintaining an industry leading cost structure, profitably developing its undeveloped Marcellus reserves, and effectively and efficiently utilizing its extensive gathering and transmission assets that are uniquely positioned in the Marcellus Shale and in close proximity to the northeastern United States markets.

The Company continues to improve its use of technology by increasing lateral lengths, reducing cluster spacing and developing multi-well pads. EQT expects to continue increasing the average lateral lengths over time; however, lateral lengths will be limited by lease boundaries in the Marcellus play unless the Company is able to pool acreage with neighboring leaseholders. Because substantially all of the Company's acreage is held by production or in fee, 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 longer laterals and multi-well pads has the additional benefit of reducing the surface environmental footprint of the Company's drilling.

The Company believes the location of its midstream assets across a wide area of the Marcellus play in southwestern Pennsylvania and northern West Virginia is a competitive advantage which uniquely positions it for growth. In light of the growth of EQT Production and other producers in the Marcellus play, EQT Midstream intends to capitalize on the growing need for gathering and transmission infrastructure in the region, especially the need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia. The 2013 gathering and transmission investments are expected to provide a platform for growth, mitigate curtailments and increase the flexibility and reliability of the Company's gathering and transmission systems.

In July 2012, the Company formed the Partnership, which is a growth-oriented master limited partnership designed to own, operate, acquire and develop midstream assets in the Appalachian Basin. 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. With the assistance of a $700,000 grant received from the Pennsylvania Department of Environmental Protection, the Company opened a public-access natural gas fueling station in Pittsburgh, Pennsylvania during 2011. Investment break-even is expected during 2013 and plans are underway for an expansion of the station. In conjunction with this project, the Company is promoting the use of natural gas fleet vehicles, including its own. EQT plans to operate 14% of its vehicle fleet, more than 200 vehicles, on natural gas by the end of 2013. In addition, the Company converted two drilling rigs to utilize natural gas in 2012, with an additional two to three expected by the end of 2013.

See "Capital Resources and Liquidity" in "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

No single customer accounted for more than 10% of revenues in 2012, 2011 or 2010.

Natural Gas Sales: EQT's produced natural gas is sold to marketers, utilities and industrial customers located mainly in the Appalachian area. 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. Changes in the market price for natural gas impact the Company's revenues, earnings and liquidity. The Company is unable to predict potential future movements in the market price for natural gas 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 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. The Company's hedging strategy and information regarding its derivative instruments is set forth in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," and in Notes 1 and 4 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 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 wellhead 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:

	2012	2011	2010
Average wellhead sales price per Mcfe sold (including hedges)	$ 4.26	$ 5.37	$ 5.62
Average wellhead sales price per Mcfe sold (excluding hedges)	$ 3.14	$ 4.85	$ 5.12

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 interconnects with Equitrans. Maintaining these interconnects provides the Company with access to geographically diverse markets.

Gathering system transportation volumes for 2012 totaled 335.4 BBtu, of which approximately 77% related to gathering for EQT Production, 13% related to third-party volumes and 10% related to volumes for other affiliates of the Company. Revenues from EQT Production and other affiliates accounted for approximately 88% of 2012 gathering revenues.

Natural Gas Transmission, Storage and Marketing: Services offered by EQT include commodity procurement, sales, delivery, risk management and other services. These operations are executed using Company owned and operated transmission and underground storage facilities as well as other contractual capacity arrangements with major pipeline and storage service providers in the eastern United States. EQT Energy uses leased storage capacity and firm transportation capacity to take advantage of price differentials and arbitrage opportunities when 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. EQT Energy's commodity procurement, sales, delivery, risk management and other services are offered to natural gas producers and energy consumers, including large industrial, utility, commercial and institutional end-users.

Equitrans' firm transportation contracts expire between 2013 and 2023. The Company anticipates that the capacity associated with these expiring contracts will be remarketed or used by affiliates such that the capacity will remain fully subscribed. In 2012, approximately 84% of transportation volumes and 81% of revenues were from affiliates.

Natural Gas Distribution: The Company's Distribution segment provides natural gas distribution services to approximately 277,400 customers, consisting of 258,500 residential customers and 18,900 commercial and industrial customers in southwestern Pennsylvania, municipalities in northern West Virginia and field line sales, also referred to as farm tap service, in eastern Kentucky and West Virginia. Distribution's service areas have a rather static population and economy.

Equitable Gas purchases gas through contracts with various sources including major and independent producers in the Appalachian area and gas marketers (including an affiliate). The gas purchase contracts contain various pricing mechanisms, ranging from fixed prices to several different index-related prices. The cost of purchased gas is Equitable Gas' largest operating expense and is passed through to customers utilizing mechanisms approved by the PA PUC, WV PSC and KY PSC. Equitable Gas is not permitted to profit from fluctuations in gas costs and does not purchase gas produced by EQT Production in order to maintain certain federal tax benefits for EQT.

Because most of its customers use natural gas for heating purposes, Equitable Gas' revenues are seasonal, with approximately 67% of calendar year 2012 revenues occurring during the winter heating season (the months of January, February, March, November and December). Significant quantities of purchased natural gas are placed in underground storage inventory during the off-peak season to accommodate higher demand during the winter heating season.

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. Key competitors for new gathering systems include independent gas gatherers and integrated energy companies. EQT competes with numerous other companies offering the natural gas marketing services. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. As a regulated utility, Equitable Gas' distribution operation experiences only limited competition with other local distribution companies in its operating area, but experiences usage pressures as a result of alternative fuels and conservation.

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 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, while in West Virginia and Pennsylvania 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 affect the costs of or increase the time of developing new or expanded pipelines and compressor stations.

EQT Midstream has both non-regulated and regulated operations. The interstate natural gas transmission systems and storage operations 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 Equitrans' rates, cost recovery mechanisms and other terms and conditions of service to Equitrans' customers. The fees or rates established under Equitrans' 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 and gathering also extends to: storage and related services; certification and construction of new facilities; extension or abandonment of 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.

EQT Production and EQT Midstream each engage in natural gas hedging activities, which include swaps and other derivatives that are regulated by, among others, the CFTC. In July 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) that, among other things, established federal oversight and regulation of swaps and certain entities that participate in swap markets. The Dodd-Frank Act authorized the CFTC to develop comprehensive regulation for types of swaps the Company may use. Among the most significant provisions of the Dodd-Frank Act are: mandatory clearing of swaps through regulated central clearing organizations and mandatory trading of such swaps on regulated exchanges or swap execution facilities (in each case, subject to certain key exceptions). The Dodd-Frank Act also required the registration and comprehensive oversight of swap dealers, which may act as swap counterparties to EQT Production and EQT Midstream.

In October 2012, joint rules of the CFTC and the SEC defining "swap" became effective and enabled the CFTC to begin implementing the new regulatory framework for swaps. As of the date of this report, the CFTC has adopted many final rules that will impose regulatory obligations on all market participants, including EQT Production and EQT Midstream. Compliance with many of these new rules will be phased in throughout 2013 and into at least 2014. The new rules may be directly applicable to EQT Production and EQT Midstream or may have an indirect effect where the rules apply to EQT Production and EQT Midstream's counterparties, which may include registered swap dealers. Other CFTC rules that may be relevant to EQT Production and EQT Midstream have yet to be finalized. Because many CFTC final rules do not have final compliance dates and other rules are still at the proposal stage, it is not possible at this time to predict the extent of the impact of the Dodd-Frank Act and new regulations on the Company's hedging program or regulatory compliance obligations. The Company anticipates, however, increased compliance costs and significant changes to current market practices as participants adapt to a new regulatory environment.

Equitable Gas' distribution rates, terms of service and certain contracts with affiliates are subject to comprehensive regulation by the PA PUC and the WV PSC. The field line sales rates in Kentucky are subject to rate regulation by the KY PSC.

Equitable Gas must usually seek the approval of one or more of its regulators prior to changing its rates. Currently, Equitable Gas passes through to its regulated customers the cost of its purchased gas and transportation activities. Equitable Gas is provided an opportunity to recover a return in addition to the costs of its distribution and gathering delivery activities. However, Equitable Gas' regulators do not guarantee recovery and may require that certain costs of operation be recovered over an extended term.

As required by Pennsylvania law, Equitable Gas has a customer assistance program that assists low-income customers with paying their gas bills. The cost of this program is recovered through rates charged to other residential customers.

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; and the pollution, preservation, remediation or protection of human health and safety, natural resources, wildlife or 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. In most instances, the regulatory frameworks relate to the handling of drilling, production and processing materials and emissions, the disposal of drilling, production and processing wastes, the protection of water and air and the protection of people and aquatic life.

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, we conduct baseline and 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 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 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 1,873 employees at the end of 2012. As of December 31, 2012, approximately 10% of the Company's workforce was subject to collective bargaining agreements. The collective bargaining agreement which covers approximately 8% of the Company's workforce will expire on July 8, 2015. The collective bargaining agreement which covers approximately 2% of the Company's workforce was extended in the fourth quarter of 2012 to January 22, 2016.

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. The Company's press releases and recent analyst presentations are also available on the Company's website.

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 year ended December 31,		
	2012	**2011**	**2010**
EQT Production:			
Natural gas sales	47%	41%	27%
EQT Midstream:			
Gathering revenue	17%	14%	13%
Distribution:			
Residential natural gas sales	12%	15%	20%

Financial Information about Segments

See Note 3 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.

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 occurs, 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; 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, margin 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 margin. A reduction in margin 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 deferral of purchased gas costs for our distribution operations, increased production taxes, increased lease operating expenses, increased exposure to credit losses resulting from potential increases in uncollectible accounts receivable from our distribution customers, increased volatility in seasonal gas price spreads for our storage assets and increased customer 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, storage and distribution 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 or render data or systems unusable, 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 and loss of sensitive confidential information. Moreover, in 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. In the Marcellus play, 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 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 2013 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, distribution infrastructure, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2013 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 2013 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

On December 19, 2012, we signed an agreement to transfer Equitable Gas Company to PNG Companies in exchange for $720 million in cash, subject to adjustment, and select midstream assets and commercial arrangements. Acquisitions, dispositions and other strategic 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 results of operations.

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 systems, pipelines and distribution systems. 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, storage and distribution businesses are, in many cases, subject to state or federal regulation. The agencies that regulate our rates 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 (including purchased gas cost recoveries) and/or expense deferrals. Additionally, we may be required to provide additional assistance to low income residential customers to help pay their bills without the ability to recover some or all of the additional assistance in rates.

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. For instance, several initiatives aimed at greenhouse gas emissions and air pollution have recently been enacted or are being considered. On January 1, 2011, the EPA began regulating greenhouse gas emissions by subjecting new facilities and major modifications to existing facilities that emit large emissions of greenhouse gas emissions to the permitting requirements of the federal Clean Air Act.

Moreover, the U.S. Congress and various states have been evaluating climate-related legislation and other regulatory initiatives that would 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.

Additionally, on April 7, 2012, the EPA issued final rules that subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) programs. The EPA's rules also include NSPS standards for the completions of hydraulically fractured gas wells, applicable to newly drilled and fractured wells as well as existing wells that are refractured. The rules under NESHAP include maximum achievable control technology standards for certain equipment not currently subject to such standards. Compliance with these initiatives and rules could result in an increase to our costs or require changes that reduce our production.

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 impact 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 cash flows and profitability.

In July 2010, Congress enacted the Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) that, among other things, authorized the CFTC to develop comprehensive regulation for the swap markets. The Dodd-Frank Act created a new structure for trading OTC swaps, a market in which we are currently a market participant. Among other things, the Dodd-Frank Act established mandatory clearing of certain standardized swaps through regulated central clearing organizations and mandatory trade execution of those swaps on regulated exchanges or swap execution facilities (in each case, subject to certain key exceptions). The CFTC's new regulatory regime requires the registration and comprehensive oversight of swap dealers. The CFTC has finalized new rules directly applicable to EQT Production and EQT Midstream. In addition, the CFTC's finalized new rules may have an indirect effect on EQT Production and EQT Midstream's counterparties, which may include registered swap dealers. As of the date of this report, certain CFTC rules that may be relevant to EQT Production and EQT Midstream remain in the proposal stage. Furthermore, there is ongoing regulatory uncertainty regarding compliance dates for finalized CFTC rules. Throughout 2012 the CFTC repeatedly delayed compliance dates for numerous new rules. Other CFTC rules have also been challenged by industry groups in federal court, further adding to regulatory uncertainty.

We anticipate that the CFTC rules will increase regulatory compliance costs for EQT Production and EQT Midstream. Additionally, any counterparties of EQT Production or EQT Midstream that register as swap dealers will be required to comply with substantial and burdensome new regulatory obligations. Compliance costs incurred by these swap dealers may make it more expensive for entities that hedge, such as EQT Production and EQT Midstream, to hedge their risks with swaps. Accordingly, it is not possible at this time to predict the extent of the impact of the Dodd-Frank Act and new regulatory regime on our hedging program. It is possible, however, that the Dodd-Frank Act and regulatory regime for swaps will make hedging more expensive, uneconomic or unavailable, which could lead to increased costs or commodity price volatility or a combination of both.

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 flow from operations or other sources. Future challenges in the global financial system, including the capital markets, may adversely affect our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. Adverse economic and market conditions could adversely affect the collectability of our trade receivables and cause our commodity hedging counterparties to be unable to perform their obligations or to seek bankruptcy protection. Future challenges in the economy could also lead to reduced demand for natural gas which could have a negative impact on our revenues 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.

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 and a qualified work force, 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 operations.

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 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.

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 12-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.

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, Kentucky and Virginia. This segment has approximately 3.5 million gross acres (approximately 62% of which are considered undeveloped), which encompass substantially all of the Company's acreage of proved developed and undeveloped natural gas and oil production properties. Approximately 540,000 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, 2012, the Company estimated its total proved reserves to be 6,004 Bcfe, consisting of proved developed producing reserves of 2,735 Bcfe, proved developed non-producing reserves of 63 Bcfe and proved undeveloped reserves of 3,206 Bcfe. Substantially all of the Company's reserves reside in continuous accumulations.

The Company's estimate of proved natural gas and oil reserves are 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 24 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 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 and liquid hydrocarbon proved reserves attributable to the Company's interests as of December 31, 2012. 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. 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 and crude oil reserves and future net cash flows is provided in Note 21 (unaudited) to the Consolidated Financial Statements.

In 2012, the Company commenced drilling operations ("spud" or "drilled") on 127 gross horizontal wells with an aggregate of approximately 700,000 feet of pay in the Marcellus play. Total proved reserves in the Marcellus play increased 25% to 4.3 Tcfe in 2012 primarily as a result of the Company's 2012 drilling program. In the Huron play, the Company drilled 7 gross horizontal wells during 2012 with an aggregate of approximately 37,000 feet of pay. Total proved reserves in the Huron play (including vertical non-shale formations) decreased approximately 11% to 1.6 Tcfe, as the Company has indefinitely ceased development in the Huron play and plans to focus its capital expenditures during the next five years on developing the Marcellus play. The Company did not drill any gross CBM wells in 2012. The CBM play had total proved reserves of 0.1 Tcfe at December 31, 2012, slightly down from 2011. Natural gas production sales volumes in 2012 from the Marcellus, Huron and CBM plays were 150.5 Bcfe, 94.9 Bcfe and 13.1 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:

	For the Year Ended December 31, 2012	2011	2010
Natural Gas:			
Average wellhead sales price to EQT Corporation per Mcf (including hedges)	$ 3.64	$ 4.40	$ 4.59
BTU Premium (ethane sold as natural gas):			
Average sales price per Btu	$ 2.83	$ 4.04	$ 4.35
NGLs:			
Average sales price per Bbl	$ 44.75	$ 60.42	$ 48.76
Crude Oil:			
Average sales price per Bbl	$ 83.95	$ 81.58	$ 70.42

For additional information on production and pricing, see “Consolidated Operational Data” in “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 and crude oil during 2012, 2011 and 2010 was $0.18, $0.20 and $0.24 per Mcfe, respectively. At December 31, 2012, the Company had approximately 51 multiple completion wells.

	Natural Gas	Oil
Total productive wells at December 31, 2012:		
Total gross productive wells	14,661	5
Total net productive wells	12,777	5
Total in-process wells at December 31, 2012:		
Total gross in-process wells	103	–
Total net in-process wells	99	–

Summary of proved oil and gas reserves as of December 31, 2012 based on average fiscal year prices:	(MMcf)	(Mbbls)
Developed	2,779,187	3,199
Undeveloped	3,206,571	–
Total proved reserves	5,985,758	3,199

Total acreage at December 31, 2012:	
Total gross productive acres	1,317,724
Total net productive acres	1,145,728
Total gross undeveloped acres	2,196,037
Total net undeveloped acres	1,909,401

As of December 31, 2012, 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 2013. 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 5 wells in 2013 and could incur the potential loss of approximately 14,000 gross undeveloped acres if this obligation is not met. The Company intends to satisfy such requirements either directly through its 2013 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, 2012, leases associated with approximately 20,000 gross undeveloped acres expire in 2013 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, however, has an active lease renewal program in areas targeted for development.

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

	For the year ended December 31,		
	2012	2011	2010
Exploratory wells:			
Productive	–	–	–
Dry	–	–	–
Development wells:			
Productive	128.5	211.2	392.1
Dry	1.0	2.0	3.0

Selected data by state (at December 31, 2012 unless otherwise noted):

	Kentucky	West Virginia	Virginia	Pennsylvania	Ohio	Total
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
Natural gas and oil production (MMcfe) – 2010	58,592	35,199	25,985	19,245	–	139,021
Average net revenue interest (%)	95.5%	88.0%	49.9%	82.4%	–	81.9%
Total gross productive wells	5,586	4,973	3,253	854	–	14,666
Total net productive wells	5,274	4,714	1,949	845	–	12,782
Total gross productive acreage	544,160	424,084	274,640	74,760	80	1,317,724
Total gross undeveloped acreage	933,358	782,515	269,877	197,652	12,635	2,196,037
Total gross acreage	1,477,518	1,206,599	544,517	272,412	12,715	3,513,761
Total net productive acreage	473,125	368,734	231,337	72,452	80	1,145,728
Total net undeveloped acreage	923,856	657,808	120,670	194,968	12,099	1,909,401
Total net acreage	1,396,981	1,026,542	352,007	267,420	12,179	3,055,129
Proved developed producing reserves (Bcfe)	1,036	802	264	633	–	2,735
Proved developed non-producing reserves (Bcfe)	2	22	–	39	–	63
Proved undeveloped reserves (Bcfe)	–	1,121	–	2,085	–	3,206
Proved developed and undeveloped reserves (Bcfe)	1,038	1,945	264	2,757	–	6,004
Gross proved undeveloped drilling locations	–	237	–	315	–	552
Net proved undeveloped drilling locations	–	237	–	311	–	548

Capital expenditures at EQT Production totaled $991.8 million during 2012, including $134.6 million for the acquisition of undeveloped property. The Company invested approximately $607 million during 2012 converting undeveloped reserves to developed reserves and $250 million on wells still in progress at year end. During the year, the Company converted 159 Bcfe of proved undeveloped reserves to proved developed reserves. The Company had additions to proved developed reserves of 214 Bcfe, the majority of which were from wells drilled that had not previously been classified as proved. Downward revisions of 171 Bcfe in proved developed reserves were spread across all areas and all plays. New proved undeveloped reserves of 1,442 Bcfe were added during 2012. These reserve extensions and discoveries were mainly due to decreased lateral spacing in one of the Company's Greene County, Pennsylvania fields and additional proved locations in the Company's Wetzel and Doddridge County, West Virginia development areas. This increase was partially offset by negative revisions of 475 Bcfe. This reduction was primarily due to the decrease in the average NYMEX natural gas price for the year and caused certain existing proved undeveloped reserves to become uneconomical in accordance with SEC pricing requirements. As of December 31, 2012, the Company's proved undeveloped reserves totaled 3.2 Tcfe and all were associated with the development of the Marcellus play. All proved undeveloped drilling locations are expected to be drilled within five years.

Proved developed non-producing reserves decreased 401 Bcfe during 2012 as compared to 2011. During 2012, the Company incurred a higher percentage of its costs on the well completion phase compared to the drilling phase because of longer laterals, reduced cluster spacing and multi-well pads. As a result, the Company changed its methodology for classifying wells as proved developed non-producing reserves until only after the fracturing process has been completed.

The Company's 2012 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 1,656 Bcfe exceeded the 2012 production of 261 Bcfe.

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

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

EQT Midstream: EQT Midstream owns or operates approximately 10,300 miles of gathering lines and 244 compressor units with approximately 285,000 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	4,200	1,700	850	10,300

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 owns and operates a FERC-regulated transmission and storage system. These operations consist of an approximately 700 mile FERC-regulated interstate pipeline system that connects to five interstate pipelines and multiple distribution companies. The system is supported by 14 associated natural gas storage reservoirs with approximately 400 MMcf per day of peak delivery capability and 32 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.

Distribution: This segment owns and operates natural gas distribution and gathering facilities as well as other general property and equipment in western Pennsylvania, West Virginia and Kentucky. The distribution operations consist of approximately 4,000 miles of pipe in Pennsylvania, West 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 "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of capital expenditures.

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 the Pennsylvania Department of Environmental Protection (PA DEP), which primarily allege violations of the Pennsylvania Oil and Gas Act, the Pennsylvania Solid Waste Management Act and/or the Pennsylvania Clean Streams Law, and the rules and regulations thereunder. 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.

Executive Officers of the Registrant (as of February 21, 2013)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Theresa Z. Bone (49)	Vice President and Corporate Controller (2007)	Elected to present position July 2007. Ms. Bone is also Vice President and Principal Accounting Officer of EQT Midstream Services, LLC, the general partner of the Partnership, the Company's publicly-traded master limited partnership, since January 2012.
Philip P. Conti (53)	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 (50)	Senior Vice President and President, Midstream, Distribution and Commercial (2003)	Elected to present position April 2010; Senior Vice President and President, Midstream and Distribution from January 2008 to April 2010. Mr. Crawford is also Executive Vice President and a Director of EQT Midstream Services, LLC, the general partner of the Partnership, since January 2012.
Martin A. Fritz (48)	Vice President and President, Midstream Operations (2006)	Elected to present position April 2010; Vice President and President Midstream from January 2008 to April 2010.
Lewis B. Gardner (55)	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.
M. Elise Hyland (53)	Vice President and President, Commercial Operations (2008)	Elected to present position April 2010; Vice President and President, Equitable Gas from February 2008 to April 2010; President Equitable Gas from November 2007 to February 2008.
Charlene Petrelli (52)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007.
David L. Porges (55)	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 (47)	Senior Vice President and President, Exploration and Production (2008)	Elected to present position April 2010; 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.

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 2012 and 2011 are summarized as follows (in U.S. dollars per share):

	2012			2011		
	High	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st Quarter	$ 56.56	$ 46.04	$ 0.22	$ 49.99	$ 43.18	$ 0.22
2nd Quarter	55.20	43.69	0.22	54.25	45.68	0.22
3rd Quarter	59.46	52.20	0.22	65.97	47.86	0.22
4th Quarter	62.74	56.45	0.22	73.10	49.54	0.22

As of January 31, 2013, there were 3,056 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, result of operations and financial conditions, strategic direction and other factors. During the period reported above, 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 to PNG Companies, the Company announced a new annual dividend rate, effective January 2013, of $0.12 per share which the Company believes better reflects the blend of the Company's core businesses remaining after giving effect to the pending transaction – a dividend supporting midstream business and a capital-intensive, rapidly growing production business. The Board of Directors has the discretion to change this new annual dividend rate at any time for the reasons described above.

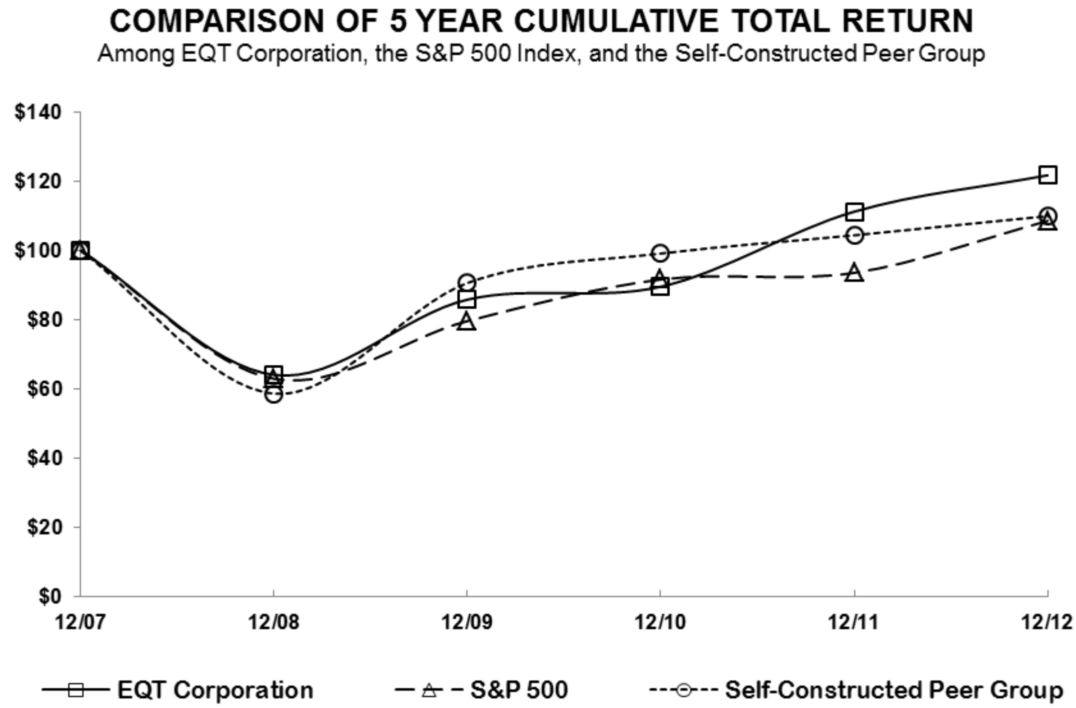
The following table sets forth the Company's repurchases of equity securities registered under Section 12 of the Securities Exchange Act of 1934, as amended, that have occurred in the three months ended December 31, 2012:

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 2012 (October 1 – October 31)	–	–	–	–
November 2012 (November 1 – November 30)	274.00	$ 59.87	–	–
December 2012 (December 1 – December 31)	1.00	$ 60.20	–	–
Total	275.00	$ 59.87	–	–

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

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 a customized peer group of 25 companies (the Self-Constructed Peer Group), whose individual companies are listed in footnote (a) below. An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2007 in the Company's common stock, in the S&P 500 index and in the Self-Constructed Peer Group. Relative performance is tracked through December 31, 2012.



	12/07	12/08	12/09	12/10	12/11	12/12
EQT Corporation	**100.00**	**64.12**	**85.87**	**89.61**	**111.27**	**121.76**
S&P 500	**100.00**	**63.00**	**79.67**	**91.67**	**93.61**	**108.59**
Self-Constructed Peer Group	**100.00**	**58.74**	**90.68**	**99.17**	**104.45**	**109.98**

(a) The Self-Constructed Peer Group 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, 2007 through December 31, 2011, at which time it was removed from the peer group calculation.

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,				
	2012	2011	2010	2009	2008
	(Thousands, except per share amounts)				
Operating revenues	$ 1,641,608	$ 1,639,934	$ 1,374,395	$ 1,311,356	$ 1,609,384
Net income attributable to EQT Corporation	$ 183,395	$ 479,769	$ 227,700	$ 156,929	$ 255,604
Earnings per share:					
Basic	$ 1.23	$ 3.21	$ 1.58	$ 1.20	$ 2.01
Diluted	$ 1.22	$ 3.19	$ 1.57	$ 1.19	$ 2.00
Total assets	$ 8,849,862	$ 8,772,719	$ 7,098,438	$ 5,957,257	$ 5,329,662
Long-term debt	$ 2,526,173	$ 2,746,942	$ 1,949,200	$ 1,949,200	$ 1,249,200
Cash dividends declared per share of common stock	$ 0.88	$ 0.88	$ 0.88	$ 0.88	$ 0.88

See Item 1A, "Risk Factors" and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes 2, 3, 6 and 7 to the Consolidated Financial Statements for a discussion of an adjustment to operating revenues for all periods and other matters that affect the comparability of the selected financial data as well as uncertainties that might affect the Company's future financial condition.

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

Consolidated Results of Operations

In 2012, EQT highlights included the following:

- Record annual production sales volumes of 258.5 Bcfe, 33% higher than 2011
- Record Marcellus sales volumes of 150.6 Bcfe, 85% higher than 2011
- Record gathered volumes of 335.4 TBtu, 30% higher than 2011
- Increased proved reserves by 12% to 6.0 Tcfe
- Completed the Partnership's IPO
- Announced an agreement to sell Equitable Gas

Net income attributable to EQT Corporation for 2012 was $183.4 million, $1.22 per diluted share, compared with $479.8 million, $3.19 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 depreciation, depletion and amortization (DD&A) and higher interest expense partially offset by increases in both production and gathered volumes and lower income tax expense.

Operating income was $470.5 million in 2012 compared to $861.3 million in 2011, a decrease of $390.8 million. In addition to the $202.9 million gain in 2011 on the dispositions of Big Sandy and Langley, the decrease from 2011 was a result of approximately 25% lower realized sales prices for production sales volumes, a 23% 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 play acreage. This increase was partially offset by the normal production decline in the Company's producing wells. The average wellhead sales price to EQT Corporation including the effect of the Company's hedging program was $4.26 per Mcfe in 2012 compared to $5.37 per Mcfe in 2011. Hedging activities resulted in an increase in the average natural gas sales price of $1.19 per Mcf in 2012 and $0.55 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 $1,171.1 million compared to $981.5 million in 2011, an increase of $189.6 million. This increase was primarily attributable to higher DD&A charges from higher production volumes at a production depletion rate of $1.54/Mcfe compared to $1.25/Mcfe in 2011 and higher production-related and selling, general and administrative (SG&A) costs consistent with the growth in produced volumes and midstream throughput.

On July 2, 2012, the Partnership, a subsidiary of the Company, 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. The Company continues to consolidate the results of the Partnership. EQT records the noncontrolling interest of the public limited partners in EQT's financial statements.

EQT's consolidated net income for 2011 was $479.8 million, $3.19 per diluted share, compared with $227.7 million, $1.57 per diluted share, for 2010. In 2011, the Company recorded $128.3 million of after-tax gains on dispositions related to the sales of Langley and Big Sandy.

Operating income increased to $861.3 million in 2011 from $470.5 million in 2010. In addition to the $202.9 million gain on the dispositions of Big Sandy and Langley and the absence of revenues and expenses associated with these assets, operating income was favorably impacted by increased production sales volumes and higher gathering and transmission revenues which more than offset the increase in operating expenses associated with higher volumes, lower storage and marketing net operating revenues and a lower average wellhead sales price to EQT Corporation.

Production sales volumes increased more than 44% in 2011 from 2010, largely associated with the Marcellus play, as a result of increased production from the 2010 and 2011 drilling programs partially offset by the normal production decline in the Company's producing wells. Gathered revenues increased as a result of a 32% increase in gathered volumes primarily related to the Company's production growth. Transmission net revenues increased as a result of higher firm transportation activity and capacity from the Equitrans 2010 Marcellus expansion project. The average wellhead sales price to EQT Corporation including the effect of the Company's hedging program was $5.37 per Mcfe in 2011 compared to $5.62 per Mcfe in 2010. Hedging activities resulted in an increase in the average natural gas sales price of $0.55 per Mcf in both 2011 and 2010.

Operating expenses for 2011 increased $77.6 million compared to 2010 primarily as a result of increased production depletion and expenses on higher produced volumes as well as higher selling, general and administrative expenses consistent with the growth of the business. These increases were partially offset by the absence of expenses associated with Big Sandy and Langley, primarily operating and maintenance expenses, and favorable adjustments for certain non-income tax matters.

See "Other Income Statement Items" for a discussion of other income, interest expense and income taxes and "Investing Activities" in "Capital Resources and Liquidity" for a discussion of capital expenditures.

Consolidated Operational Data

EQT Production's average wellhead sales price is calculated by allocating some of its revenues to EQT Midstream for the gathering and transportation of produced gas. The following operational information presents detailed gross liquid and natural gas operational information as well as midstream deductions to assist the understanding of the Company's consolidated operations.

in thousands (unless noted)	Years Ended December 31, 2012	2011	2010
LIQUIDS			
NGLs:			
Sales Volume (MMcfe)	13,052	11,579	10,454
Sales Volume (Mbbls)	3,484	3,076	2,712
Gross Price ($/Mbbls)	$ 44.75	$ 60.42	$ 48.76
Gross NGL Revenue	$ 155,926	$ 185,845	$ 132,244
BTU Premium (Ethane sold as natural gas):			
Sales Volume (MMbtu)	22,494	16,124	11,404
Price ($/MMbtu)	$ 2.83	$ 4.04	$ 4.35
BTU Premium Revenue	$ 63,668	$ 65,168	$ 49,622
Oil:			
Sales Volume (MMcfe)	1,587	1,248	718
Sales Volume (Mbbls)	264	208	120
Net Price ($/Mbbls)	$ 83.95	$ 81.58	$ 70.42
Net Oil Revenue	$ 22,161	$ 16,968	$ 8,428
Total Liquids Revenue	$ 241,755	$ 267,981	$ 190,294
GAS			
Sales Volume (MMcf)	243,886	181,566	123,442
NYMEX Price ($/Mcf) (a)	$ 2.83	$ 4.04	$ 4.35
Gas Revenues	$ 690,293	$ 733,814	$ 537,150
Basis	(960)	24,047	17,527
Gross Gas Revenue (unhedged)	$ 689,333	$ 757,861	$ 554,677
Total Gross Gas & Liquids Revenue (unhedged)	$ 931,088	$ 1,025,842	$ 744,972
Hedge impact	290,557	101,047	67,449
Total Gross Gas & Liquid Revenue	$ 1,221,645	$ 1,126,889	$ 812,421
Total Sales Volume (MMcfe)	258,525	194,393	134,614
Average hedge adjusted price ($/Mcfe)	$ 4.72	$ 5.80	$ 6.04
Midstream Revenue Deductions ($ / Mcfe)			
Gathering to EQT Midstream	$ (1.02)	$ (1.11)	$ (1.32)
Transmission to EQT Midstream	(0.19)	(0.22)	(0.37)
Third-party gathering and transmission*	(0.36)	(0.31)	(0.42)
Third-party processing	(0.10)	(0.12)	-
Total midstream revenue deductions	(1.67)	(1.76)	(2.11)
Average wellhead sales price to EQT Production	$ 3.05	$ 4.04	$ 3.93
EQT Revenue ($ / Mcfe)			
Revenues to EQT Midstream	$ 1.21	$ 1.33	$ 1.69
Revenues to EQT Production	3.05	4.04	3.93
Average wellhead sales price to EQT Corporation	$ 4.26	$ 5.37	$ 5.62

(a) The Company's annual volume weighted NYMEX price (average NYMEX natural gas price ($/Mcf) was $2.79, $4.04 and $4.39 in the years ended December 31, 2012, 2011 and 2010, respectively).

* 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 $0.04 per Mcfe for the year ended 2012. 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 for the year ended 2011. The El Paso 300 line came online in 2011 and thus, there was no unused capacity sold in the year ended 2010.

Business Segment Results

Business segment operating results 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 $23.3 million, $29.3 million and $15.1 million were not allocated to the operating segments for the years ended December 31, 2012, 2011 and 2010, respectively. As part of the 2012 budgeting process, the Company allocated additional corporate overhead charges to the operating segments.

The Company has reported the components of each segment's operating income 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 wellhead 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 3 to the Consolidated Financial Statements.

EQT Production

Results of Operations

	Years Ended December 31,				
	2012	**2011**	**% change 2012 - 2011**	**2010**	**% change 2011 - 2010**
OPERATIONAL DATA					
Natural gas, NGL and crude oil production (MMcfe) (a)	260,963	198,821	31.3	139,021	43.0
Company usage, line loss (MMcfe)	(2,438)	(4,428)	(44.9)	(4,407)	0.5
Total production sales volumes (MMcfe)	258,525	194,393	33.0	134,614	44.4
Average daily sales volumes (MMcfe/d)	706	533	32.5	369	44.4
Sales volume detail (MMcfe):					
Horizontal Marcellus Play	150,552	81,602	84.5	25,474	220.3
Horizontal Huron Play	36,934	40,081	(7.9)	38,816	3.3
CBM Play	13,084	13,682	(4.4)	13,493	1.4
Other (vertical non-CBM)	57,955	59,028	(1.8)	56,831	3.9
Total production sales volumes	258,525	194,393	33.0	134,614	44.4
Average wellhead sales price to EQT Production ($/Mcfe)	$ 3.05	$ 4.04	(24.5)	$ 3.93	2.8
Lease operating expenses, excluding production taxes (LOE) ($/Mcfe)	$ 0.18	$ 0.20	(10.0)	$ 0.24	(16.7)
Production taxes ($/Mcfe) (b)	$ 0.16	$ 0.20	(20.0)	$ 0.24	(16.7)
Production depletion ($/Mcfe)	$ 1.54	$ 1.25	23.2	$ 1.26	(0.8)
Depreciation, depletion and amortization (DD&A) (thousands):					
Production depletion	$ 401,456	$ 248,286	61.7	$ 175,629	41.4
Other DD&A	8,172	8,858	(7.7)	8,070	9.8
Total DD&A (thousands)	$ 409,628	$ 257,144	59.3	$ 183,699	40.0
Capital expenditures (thousands) (c)	$ 991,775	$ 1,087,840	(8.8)	$ 1,245,914	(12.7)

	Years Ended December 31,				
	2012	2011	% change 2012 - 2011	2010	% change 2011 - 2010
FINANCIAL DATA (thousands)					
Total net operating revenues	$ 793,773	$ 791,285	0.3	$ 537,657	47.2
Operating expenses:					
LOE, excluding production taxes	46,212	40,369	14.5	33,784	19.5
Production taxes (b)	49,943	40,542	23.2	33,630	20.6
Exploration expense	10,370	4,932	110.3	5,368	(8.1)
Selling, general and administrative (SG&A)	89,707	61,200	46.6	57,689	6.1
DD&A	409,628	257,144	59.3	183,699	40.0
Total operating expenses	605,860	404,187	49.9	314,170	28.7
Operating income	$ 187,913	$ 387,098	(51.5)	$ 223,487	73.2

(a) Natural gas, NGL and oil production represents the Company's interest in natural gas, NGL and oil production measured at the wellhead. It is equal to the sum of total sales volumes and Company usage and line loss.

(b) Production taxes include severance and production-related ad valorem and other property taxes. In 2012, production taxes also include the Pennsylvania impact fee of $15.3 million. The production taxes unit rate for 2012 excludes the impact of $6.7 million paid upon enactment in that year for pre-2012 Marcellus wells.

(c) Capital expenditures in the EQT Production segment include $92.6 million of liabilities assumed in exchange for producing properties as part of the ANPI transaction in 2011 and $230.7 million of undeveloped property which was acquired with EQT common stock in 2010.

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 wellhead 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 25% decrease in the average wellhead 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 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 $0.99 per Mcfe decrease in the average wellhead 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 wellhead 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 drilled 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 wellhead 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.

Year Ended December 31, 2011 vs. December 31, 2010

EQT Production's operating income totaled $387.1 million for 2011 compared to $223.5 million for 2010, an increase of $163.6 million between years, primarily due to increased production sales volumes and higher wellhead sales prices to EQT Production, partially offset by an increase in DD&A and other operating costs resulting from higher volumes.

Total net operating revenues were $791.3 million for 2011 compared to $537.7 million for 2010. The $253.6 million increase in operating revenues was primarily due to a 44% increase in production sales volumes as well as a 3% increase in the average wellhead sales price to EQT Production. The increase in sales volumes was the result of increased production from the 2010 and 2011 drilling programs, primarily in the Marcellus play, as well as the acquisition of producing properties associated with acquiring the Class A interest in a trust thereby acquiring 100% of the net profits interest associated with the producing properties (the ANPI transaction), as described in Note 7 to the Consolidated Financial Statements in May 2011 which added 5.5 Bcfe of sales volumes in 2011. This increase was partially offset by the normal production decline in the Company's producing wells. The $0.11 per Mcfe increase in the average wellhead sales price to EQT Production was primarily due to lower gathering rates and higher sales prices for NGLs and oil in 2011 partially offset by an 8% decrease in the average NYMEX price compared to 2010. The average wellhead sales price was also impacted favorably from selling excess transmission capacity on the Tennessee Gas Pipeline 300-Line in the fourth quarter of 2011.

Operating expenses totaled $404.2 million for 2011 compared to $314.2 million for 2010. The 29% increase in operating expenses was primarily the result of increased DD&A, production taxes and LOE. The depletion expense increased as a result of higher volumes in 2011 partially offset by a slightly lower overall depletion rate. Production taxes increased due to higher revenues and increased assessments in certain jurisdictions that impose these taxes in the year of production. The increase in LOE was primarily the result of increased activity in 2011 as well as the elimination, as part of the ANPI transaction, of certain operating expense reimbursement agreements. Lower costs for road and location maintenance due to less severe weather in 2011 partly offset these increases. SG&A increased due to higher overhead and commercial services costs associated with the growth of the company and higher franchise tax expense. These increases were partially mitigated by a charge in 2010 related to the buy-out of excess contractual capacity for water treatment and lower professional services, hiring and relocation costs in 2011.

EQT Midstream

Results of Operations

	Years Ended December 31,				
	2012	**2011**	**% change 2012 - 2011**	**2010**	**% change 2011 – 2010**
OPERATIONAL DATA					
Gathered volumes (BBtu)	335,407	258,179	29.9	195,642	32.0
Average gathering fee ($/MMBtu)	$ 0.90	$ 0.97	(7.2)	$ 1.11	(12.6)
Gathering and compression expense ($/MMBtu) (a)	$ 0.24	$ 0.30	(20.0)	$ 0.37	(18.9)
Transmission pipeline throughput (BBtu)	221,944	159,384	39.3	109,165	46.0
Net operating revenues (thousands):					
Gathering	$ 302,255	$ 249,607	21.1	$ 212,170	17.6
Transmission	104,501	90,405	15.6	84,190	7.4
Storage, marketing and other	42,693	64,614	(33.9)	100,097	(35.4)
Total net operating revenues	$ 449,449	$ 404,626	11.1	$ 396,457	2.1
Unrealized losses on derivatives and inventory (thousands) (b)	$ 9,225	$ 755	1,121.9	$ 379	99.2
Capital expenditures (thousands)	$ 375,731	$ 242,886	54.7	$ 193,128	25.8

FINANCIAL DATA (thousands)					
Total operating revenues	$ 505,498	$ 525,345	(3.8)	$ 580,698	(9.5)
Purchased gas costs	56,049	120,719	(53.6)	184,241	(34.5)
Total net operating revenues	449,449	404,626	11.1	396,457	2.1
Operating expenses:					
Operating and maintenance (O&M)	97,400	83,907	16.1	107,601	(22.0)
SG&A	49,943	49,901	0.1	48,127	3.7
DD&A	64,782	57,135	13.4	61,863	(7.6)
Total operating expenses	212,125	190,943	11.1	217,591	(12.2)
Gain on dispositions	–	202,928	(100.0)	–	100.0
Operating income	$ 237,324	$ 416,611	(43.0)	$ 178,866	132.9

(a) Gathering and compression expense for the full year 2011 excludes $7.1 million of favorable adjustments for certain non-income tax reserves.
(b) Included in storage, marketing and other net operating revenues.

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.

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 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.

Year Ended December 31, 2011 vs. December 31, 2010

EQT Midstream's operating income totaled $416.6 million for 2011, including gains on the dispositions of Langley and Big Sandy of $202.9 million, compared to $178.9 million for 2010. In addition to the gains, operating income increased as a result of increased gathering and transmission volumes combined with lower operating expenses. These favorable variances were partially offset by decreased storage, marketing and other net operating revenues and a lower average gathering fee.

Total net operating revenues were $404.6 million for 2011 compared to $396.5 million for 2010. The increase in total net operating revenues was due to a $37.4 million increase in gathering net operating revenues and a $6.2 million increase in transmission net operating revenues, partly offset by a $35.5 million decrease in storage, marketing and other net operating revenues.

Gathering net operating revenues increased due to a 32% increase in gathered volumes, partially offset by a 13% decrease in the average gathering fee. This increase in gathered volumes was driven primarily by higher produced natural gas volumes gathered for EQT Production in the Marcellus play. The decrease in the average gathering fee was a result of lower gathering rates charged to affiliates and other shippers in the Marcellus play.

Transmission net operating revenues increased in 2011 as a result of higher firm transportation activity from affiliated shippers due to the increased Marcellus volumes and increased capacity from the Equitrans 2010 Marcellus expansion project, partly offset by the absence of revenues from the sale of Big Sandy.

Storage, marketing and other net operating revenue decreased from the prior year primarily as a result of a decrease in natural gas volumes marketed for third parties utilizing pipeline capacity, lower net revenue from NGLs marketed for non-affiliated producers, lower margins due to reduced commodity prices and lower price spreads and volatility. Higher NGL prices were more than offset by the loss of processing fees associated with the sale of Langley.

Total operating revenues decreased in 2011 by $55.4 million primarily as a result of lower sales prices on decreased commercial activity and a lower gathering rate partially offset by an increase in gathered volumes and increased transmission revenue. Total purchased gas costs decreased as a result of decreased commercial activity.

Operating expenses totaled $190.9 million for 2011 compared to $217.6 million for 2010. The decrease in operating expenses was primarily due to decreases of $23.7 million in O&M and $4.7 million in DD&A. The decrease in O&M was primarily due to the absence of operating expenses associated with Langley and Big Sandy and reductions in certain non-income property tax reserves partly offset by increased compensation costs. The decrease in DD&A was primarily due to the sales of Big Sandy and Langley, partly offset by increased depreciation on increased investment in gathering and compression infrastructure.

Distribution

Results of Operations

	Years Ended December 31,				
	2012	2011	% change 2012 - 2011	2010	% change 2011 – 2010
OPERATIONAL DATA					
Heating degree days (30-year average = 5,710)....	4,693	5,189	(9.6)	5,516	(5.9)
Residential sales and transportation volume (MMcf)	19,326	22,333	(13.5)	23,132	(3.5)
Commercial and industrial volume (MMcf)	27,651	28,752	(3.8)	27,124	6.0
Total throughput (MMcf)	46,977	51,085	(8.0)	50,256	1.6
Net operating revenues (thousands):					
Residential	$ 105,382	$ 115,912	(9.1)	$ 117,418	(1.3)
Commercial and industrial.................................	45,084	48,968	(7.9)	48,614	0.7
Off-system and energy services..........................	19,557	22,672	(13.7)	21,365	6.1
Total net operating revenues	$ 170,023	$ 187,552	(9.3)	$ 187,397	0.1
Capital expenditures (thousands)	$ 28,745	$ 31,313	(8.2)	$ 36,619	(14.5)
FINANCIAL DATA (thousands)					
Total operating revenues.......................................	$ 313,990	$ 419,678	(25.2)	$ 474,143	(11.5)
Purchased gas costs...	143,967	232,126	(38.0)	286,746	(19.0)
Net operating revenues.....................................	170,023	187,552	(9.3)	187,397	0.1
Operating expenses:					
O&M	42,838	43,383	(1.3)	44,047	(1.5)
SG&A...	34,117	31,524	8.2	35,994	(12.4)
DD&A	24,454	25,747	(5.0)	24,174	6.5
Total operating expenses................................	101,409	100,654	0.8	104,215	(3.4)
Operating income...	$ 68,614	$ 86,898	(21.0)	$ 83,182	4.5

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

Distribution's operating income totaled $68.6 million for 2012 compared to $86.9 million for 2011. The decrease in operating income was primarily due to record warm weather during 2012.

Net operating revenues were $170.0 million for 2012 compared to $187.6 million for 2011. Net operating revenues from residential customers decreased $10.5 million as a result of weather and related customer usage patterns. Weather was 10% warmer in 2012 as compared to 2011 and 18% warmer than the 30-year National Oceanic and Atmospheric Administration (NOAA) average for the Company's service territory. According to NOAA, it was the warmest twelve-month calendar period on record in the Company's service territory. Commercial and industrial net operating revenues also decreased by $3.9 million primarily due to warmer weather and related customer usage patterns of $3.0 million and lower revenue associated with competitive contract renewals in 2012. Off-system and energy services net operating revenues decreased $3.1 million primarily due to a $2.4 million favorable change in estimated recoverable costs in 2011 and $2.0 million in fewer asset optimization opportunities realized during 2012 as compared to 2011. These declines were partially offset by higher revenues from gathering activities resulting from increased rates.

Decreases in total operating revenues and purchased gas costs were primarily due to lower customer throughput as a result of warmer weather during 2012, a decrease in the commodity component of tariff rates and a decrease in asset optimization off-system and energy services revenues.

Operating expenses totaled $101.4 million for 2012 compared to $100.7 million for 2011, as a $2.6 million increase in SG&A expenses was partly offset by a decrease in DD&A and O&M expenses. The increase in SG&A expenses was primarily due to a $3.0 million reduction of certain non-income tax reserves in 2011 as a result of settlements with tax authorities partly offset by lower bad debt expense of $0.9 million, which was primarily the result of a lower commodity component of residential tariff rates in 2012 and the Company's favorable collections experience. The Company will continue to closely monitor its collection rates and adjust its reserve for uncollectible accounts as necessary. The decrease in DD&A was primarily due to a change in the assumptions used in valuing the segment's asset retirement obligation.

Year Ended December 31, 2011 vs. December 31, 2010

Distribution's operating income totaled $86.9 million for 2011 compared to $83.2 million for 2010. The increase in operating income was primarily the result of an increase in estimated recoverable costs in 2011, an increase in the Company's West Virginia base rates and lower operating expenses. These increases were partly offset by warmer weather in 2011.

Net operating revenues were $187.6 million for 2011 compared to $187.4 million for 2010 as an increase in estimated recoverable costs in 2011 was substantially offset by a decrease in residential net operating revenues. Net operating revenues from residential customers decreased $1.5 million as a result of warmer weather partially offset by the full year impact of the Company's West Virginia base rate increase, which was approved in August 2010. The weather in Distribution's service territory in 2011 was 6% warmer than 2010 and 9% warmer than the territory's 30-year NOAA average. Commercial and industrial net operating revenues increased $0.4 million primarily as a result of an increase in usage by one industrial customer. The high volume sales to this industrial customer had low unit margins and did not ratably impact total net operating revenues. Off-system and energy services net operating revenues were higher as a result of a change in estimated recoverable costs in 2011 offset by fewer asset optimization opportunities realized in 2011. A decrease in the commodity component of residential tariff rates and fewer asset optimization transactions resulted in a decrease in both total operating revenues and purchased gas costs.

Operating expenses totaled $100.7 million for 2011 compared to $104.2 million for 2010. The decrease in operating expenses was primarily the result of lower bad debt expense and the reduction of certain non-income tax reserves resulting from settlements with tax authorities. These decreases were partially offset by an increase in other compensation related costs and depreciation expense in 2011. The decrease in bad debt expense was primarily the result of a decrease in the commodity component of residential tariff rates and the Company's favorable collections experience.

Other Income Statement Items

Other Income

	Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
Other income	$ 15,965	$ 34,138	$ 12,898

Other income includes equity in earnings of nonconsolidated investments, primarily the Company's investments in Nora Gathering, LLC of $6.1 million, $7.2 million and $9.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Other income for the year ended December 31, 2012 also included $6.9 million of AFUDC compared to $4.0 million in 2011, a $2.9 million increase as a result of further construction on the Equitrans Sunrise Pipeline project, which was placed into service during 2012.

Other income increased in 2011 compared to 2010 as a result of the $10.1 million pre-tax gain on the ANPI transaction, an $8.5 million gain on sales of available-for-sale securities and an increase in the equity portion of AFUDC as a result of construction on the Equitrans Sunrise Pipeline project.

Other income for the year ended December 31, 2010 also included a $2.1 million gain on sales of available-for-sale securities.

Interest Expense

	Years Ended December 31,		
	2012	**2011**	**2010**
		(Thousands)	
Interest expense	$ 184,786	$ 136,328	$ 128,157

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 a $23.3 million payment to close a forward-starting interest rate swap settled in 2012. This increase was 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.

Interest expense increased by $8.2 million from 2010 to 2011 as a result of the Company's increased debt to fund its continued investment in drilling and midstream infrastructure during the year. The increase in interest from the Company's November 2011 issuance of $750 million 4.875% notes and the debt assumed in the May 2011 ANPI transaction was partially offset by higher capitalized interest on increased Marcellus well development. The Company also paid higher commitment fees under the terms of its $1.5 billion revolving credit facility entered into on December 8, 2010 than under the previous facility.

Weighted average annual interest rates on the Company's long-term debt were 6.4%, 6.8% and 6.8% for 2012, 2011 and 2010, respectively. Weighted average annual interest rates on the Company's short-term debt were 1.8% and 0.7% for 2011 and 2010, respectively. The Company had no short-term debt in 2012.

Income Taxes

	Years Ended December 31,		
	2012	**2011**	**2010**
		(Thousands)	
Income taxes	$ 105,296	$ 279,360	$ 127,520

Income tax expense decreased by $174.1 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 36.8% to 34.9%. 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 the impact of the Partnership's IPO. The effective tax rate is impacted by the recent IPO which modified the Midstream ownership structure and now reflects Partnership earnings for which the noncontrolling public limited partners are directly responsible for the related income taxes. The Company consolidates the pre-tax income related to the noncontrolling public limited partners' share of partnership earnings but excludes the related tax provision. 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.

Income tax expense increased by $151.8 million from 2010 to 2011 as a result of higher pre-tax income and an increase in the Company's effective income tax rate from 35.9% to 36.8%. The Company's regulated business accounts for tax deductible repair costs as a permanent difference, as the related deferred taxes are recoverable in rates. The increase in the effective tax rate in 2011 was primarily the result of the tax benefit for these repair costs being higher in 2010 than in 2011. State income taxes were also higher in 2011 due to a shift in the Company's non-regulated business to states with higher income tax rates. Other rate reconciling items had a larger percentage impact on the effective tax rate in 2010 than 2011 due to significantly higher pre-tax income in 2011.

The Company was in an overall federal tax net operating loss (NOL) position for 2012, 2011 and 2010. For federal income tax purposes, the Company deducts approximately 83% of drilling costs as intangible drilling costs (IDC) in the year incurred. The primary reasons for the Company's net operating loss positions are the IDC deduction resulting from the Company's drilling program and the accelerated tax deprecation for expansion of gathering infrastructure which provide tax deductions in excess of book deductions. IDCs, however, are sometimes limited for purposes of the alternative minimum tax (AMT) and can result in the Company paying AMT even when generating a regular tax NOL. See Note 8 to the Consolidated Financial Statements for further discussion of the Company's income taxes.

Net Income Attributable to Noncontrolling Interests

As a result of the Partnership's IPO in 2012, net income attributable to noncontrolling interests was $13.0 million for the year ended December 31, 2012.

Outlook

The Company is committed to profitably developing its Marcellus reserves through environmentally responsible, cost-effective and technologically advanced horizontal drilling. The market price for natural gas can be volatile, as demonstrated by significant declines in late 2011 and early 2012, 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 thus 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.

Capital spending for well development (primarily drilling) in 2013 is expected to be approximately $1.15 billion to support the drilling of approximately 172 gross wells, including 153 Marcellus wells, 11 Upper Devonian wells and eight wells in the Utica Shale of Ohio. Sales volumes are expected to be between 335 and 340 Bcfe for an anticipated production sales volume growth of approximately 31% in 2013.

In addition, the Company plans to spend $400 million on midstream infrastructure in 2013 to support its production growth and expects gathering and transmission volumes to increase as a result of this expansion. EQT Midstream expects to add approximately 400 MMcf per day of incremental gathering capacity and approximately 450 MMcf per day of transmission capacity in 2013. The 2013 capital spending plan is expected to be funded by cash on hand, cash flow generated from operations and proceeds from expected midstream asset sales (dropdowns) to the Partnership.

On December 19, 2012, the Company and its direct wholly-owned subsidiary Holdco executed the Master Purchase Agreement with PNG Companies, pursuant to which EQT and Holdco will transfer 100% of their ownership interests of Equitable Gas and Homeworks to PNG Companies in exchange for cash and select midstream assets of, and new commercial arrangements with, PNG Companies and its affiliates. Homeworks and Equitable Gas are direct wholly-owned subsidiaries of Holdco. Peoples is a portfolio company of SteelRiver Infrastructure Partners. The transaction (or portions thereof) requires the approval of the PA PUC, the WV PSC, the KY PSC and the FERC. In addition, the transaction is subject to review under the Hart-Scott-Rodino Act. The agreements provide that such approvals and review must be complete by December 19, 2013, subject to certain extension rights. These approvals and review may not be received or completed within the time allowed.

We continue to focus on achieving our objective of maximizing shareholder value via an overarching strategy of economically accelerating the monetization of our asset base and prudent pursuit of 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 to the Partnership or others and joint ventures, to monetize the value of mature assets for the re-deployment into higher-growth Marcellus Shale development.

Capital Resources and Liquidity

The Company's primary sources of cash for 2012 were cash flows from operating activities and a cash distribution from the Partnership in connection with the Partnership's issuance of common units in the IPO. The Company's primary use of cash in 2012 was for capital expenditures and repayments of long-term debt.

Operating Activities

The Company's net cash provided by operating activities decreased $94.4 million from $915.3 million in 2011 to $820.9 million in 2012. The decline in operating receipts was a result of several factors, including a 25% decline in average wellhead 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 and higher operating expenses. This decrease was partially offset by a 33% increase in the production of natural gas, a 30% increase in gathered volumes and a $19.6 million decrease in cash payments for income taxes.

The Company's net cash provided by operating activities during 2011 was $915.3 million compared to $789.7 million for the same period of 2010. The increase in cash flows provided by operating activities was primarily attributable to higher operating receipts as a result of increased production in 2011, which more than offset the negative cash flow impact of paying $47.2 million in taxes in 2011 compared to receiving tax refunds of $129.5 million in 2010.

Investing Activities

Cash flows used in investing activities totaled $1,394.5 million for 2012 as compared to $624.3 million for 2011. The $770.2 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 capital expenditures by $125.1 million from 2011 to 2012.

Cash flows used in investing activities totaled $624.3 million for 2011 as compared to $1,239.4 million for 2010. The decrease in cash flows used in investing activities was primarily attributable to 2011 proceeds from the sales of Big Sandy, Langley and available-for-sale securities. Capital expenditures increased $27.3 million to $1,274.3 million in 2011. See the discussion of capital expenditures below.

Capital Expenditures

	2013 Forecast	2012 Actual	2011 Actual	2010 Actual
Well development (primarily drilling)	$ 1,150 million	$ 857 million	$ 938 million	$ 888 million
Property acquisitions *	–	$ 135 million	$ 150 million	$ 358 million
Midstream infrastructure	$ 400 million	$ 376 million	$ 243 million	$ 193 million
Distribution infrastructure and other corporate items	$ 45 million	$ 31 million	$ 36 million	$ 39 million
Total	$ 1,595 million	$1,399 million	$ 1,367 million	$ 1,478 million
Less: non-cash	–	–	$ 93 million	$ 231 million
Total cash capital expenditures	$ 1,595 million	$1,399 million	$ 1,274 million	$ 1,247 million

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

Capital expenditures for drilling and development totaled $857 million and $938 million during 2012 and 2011, respectively. The Company drilled 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 horse power of compression primarily in the Marcellus play. EQT Midstream also added 455 MMcfe per day of incremental gathering capacity and 700 MMcfe per day of transmission capacity in 2012. During 2011, midstream capital expenditures were $243 million. EQT Midstream turned in-line 46 miles of pipeline and 20,000 horse power of compression primarily within the Marcellus play in 2011.

Capital expenditures at Distribution totaled $29 million and $31 million during 2012 and 2011, respectively, principally for pipeline replacement.

Capital expenditures for drilling and development totaled $938 million and $888 million during 2011 and 2010, respectively. The Company drilled 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, compared to 489 gross wells (395 net wells) in 2010, including 90 horizontal Marcellus wells with approximately 300,000 feet of pay and 236 horizontal Huron wells with approximately 1.0 million feet of pay. Capital expenditures for 2011 also included $57 million for undeveloped property acquisitions, primarily within the Marcellus play and $93 million of liabilities assumed in exchange for producing properties in the ANPI transaction. Capital expenditures for 2010 included $358 million for undeveloped property acquisitions, $231 million of which was non-cash.

Capital expenditures for the midstream operations totaled $243 million for 2011. During the year, EQT Midstream turned in-line 46 miles of pipeline and 20,000 horse power of compression primarily in the Marcellus play. During 2010, midstream capital expenditures were $193 million. EQT Midstream turned in-line 132 miles of pipeline and 21,000 horse power of compression primarily within the Huron play in 2010.

Capital expenditures at Distribution totaled $31 million and $37 million during 2011 and 2010, respectively, principally for pipeline replacement.

Financing Activities

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 issuance of common units, 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.

Cash flows provided by financing activities totaled $540.3 million for 2011 as compared to $449.7 million for 2010. During 2011, the Company issued $750 million of 4.875% Senior Notes due November 15, 2021. The proceeds of these notes are to be used for general corporate purposes. The Company also repaid short-term loans of $53.7 million. In 2010, the Company received $537.2 million from a common stock offering.

In December 2012, in connection with its announcement of its definitive agreement to transfer Equitable Gas to PNG Companies, the Company announced its intent to reduce its annual dividend rate, effective January 2013, to

$0.12 per share, which the Company believes better reflects the blend of the Company's core businesses remaining after giving effect to the pending transaction – a dividend supporting midstream business and a capital-intensive, rapidly growing production business. The Company expects the favorable impact on cash provided by financing activities of the decline in the dividend rate to be partly offset by distributions to noncontrolling interests of the Partnership.

Short-term Borrowings

EQT primarily utilizes short-term borrowings to fund capital expenditures in excess of cash flow from operating activities until they can be permanently financed, to ensure sufficient levels of inventory and to fund required margin deposits on derivative commodity instruments. The amount of short-term borrowings used for inventory transactions is driven by the seasonal nature of the Company's natural gas distribution and marketing operations. Margin deposit requirements vary based on natural gas commodity prices, our credit ratings and the amount and type of derivative commodity instruments.

The Company has 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. 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 rating. Fixed period Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the Company's then current credit rating.

The Company had no loans or letters of credit outstanding under its revolving credit facility as of December 31, 2012 and 2011. For the years ended December 31, 2012 and 2011, the Company incurred commitment fees averaging approximately 25 basis points and 30 basis points, respectively, to maintain credit availability under the revolving credit facility.

There were no short-term loans outstanding at any time during 2012. The maximum amount of outstanding short-term loans at any time during the year ended December 31, 2011 was $104.0 million. The average daily balance of short-term loans outstanding during the year ended December 31, 2011 was approximately $5.5 million at a weighted average annual interest rate of 1.81%.

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

In connection with the IPO, the Partnership entered into 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 year ended December 31, 2012. For the year ended December 31, 2012, the Partnership incurred commitment fees averaging approximately 25 basis points to maintain credit availability under the revolving credit facility.

Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at December 31, 2012. 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 its access to the credit markets.

Rating Service	Senior Notes	Short-Term Rating	Outlook
Moody's Investors Service (Moody's)	Baa2	P-2	Ratings under review
Standard & Poor's Ratings Services (S&P)	BBB	A-2	Stable
Fitch Ratings (Fitch)	BBB-	F3	Stable

In response to the Company's announcement of the Master Purchase Agreement with PNG Companies on December 20, 2012, the ratings agencies took the following actions:

- Moody's placed EQT's ratings of Baa2 and P-2 under review for downgrade;
- S&P confirmed EQT's ratings of BBB, A-2 with a stable outlook; and
- Fitch downgraded EQT's ratings to BBB-/F3 from BBB/F2.

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 instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. The most significant default events include maintaining covenants with respect to maximum debt-to-total capitalization ratio, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company's current 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. As of December 31, 2012, the Company was in compliance with all debt provisions and covenants.

The Partnership's credit facility contains various covenants and restrictive provisions that, if not complied with, could require early payment or similar action, including a requirement 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, 2012, the Partnership was in compliance with all debt provisions and covenants.

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 fixed price swaps, collars and futures.

As of January 24, 2013, the approximate volumes and prices of the Company’s hedge position for 2013 through 2015 production were:

	2013	2014	2015
Swaps			
Total Volume (Bcf)	121	79	65
Average Price per Mcf (NYMEX)*	$ 4.70	$ 4.53	$ 4.60
Collars			
Total Volume (Bcf)	25	24	23
Average Floor Price per Mcf (NYMEX)*	$ 4.95	$ 5.05	$ 5.03
Average Cap Price per Mcf (NYMEX)*	$ 9.09	$ 8.85	$ 8.97

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

See Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” and Note 4 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 $192 million as of December 31, 2012, extending at a decreasing amount for approximately 15 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 FASB 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.

Rate Regulation

As described under “Regulation” in Item 1, “Business,” the Company’s distribution operations, transmission and storage operations and a portion of its gathering operations are subject to various forms of regulation. As described in Notes 1 and 11 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	2013	2014-2015	2016-2017	2018+
			(Thousands)		
Purchase obligations	$ 2,032,766	$ 239,392	$ 330,363	$ 286,659	$ 1,176,352
Long-term debt	2,521,570	23,204	177,173	2,993	2,318,200
Interest payments	1,098,071	160,268	315,774	299,407	322,622
Operating leases	165,366	39,677	48,524	22,796	54,369
Pension and other post-retirement benefits	150,115	9,812	18,739	17,102	104,462
Total contractual obligations	$ 5,967,888	$ 472,353	$ 890,573	$ 628,957	$ 3,976,005

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. Amounts included in the above table for capacity released under long-term agreements approximate $75.0 million and $27.4 million in 2013 and 2014, respectively.

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 $99.9 million as of December 31, 2012. The Company has subleased some of these facilities. Sublease payments to the Company total $28.1 million and are not netted from the amounts presented in the above table. 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 four years. These obligations totaled approximately $65.4 million as of December 31, 2012.

As discussed in Note 8 to the Consolidated Financial Statements, the Company had a total reserve for unrecognized tax benefits at December 31, 2012 of $18.4 million, of which $14.6 million would primarily reduce the net operating loss carryover and thus is offset against deferred tax assets. 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 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.

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 EQT'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 whenever 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 proved oil and gas properties and compares those future cash flows to the carrying values of the applicable properties. The estimated future cash flows used to test properties for recoverability are based on proved 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. Unproved properties had a net book value of $385.6 million, $358.8 million and $445.9 million in 2012, 2011 and 2010, 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 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 net operating loss carryforwards, an alternative minimum tax credit carryforward, incentive compensation and deferred compensation plans and pension and other post-retirement benefits recorded in other comprehensive income. The Company has established a valuation allowance against a portion of the deferred tax assets related to the state net operating loss 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 8 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.

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, to hedge natural gas inventory and to hedge exposure to fluctuations in interest rates. 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 other comprehensive income (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. See "Commodity Risk Management" above, Item 7A, "Quantitative and Qualitative Disclosures About

Market Risk" and Note 4 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 counterparty credit rating 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 commodity 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, by changes in the effectiveness of cash flow hedges due to changes in 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 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 drilled. 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 (2011 VDA), 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 units are treated as equity awards. Awards under the 2010 Executive Performance Incentive Program (2010 EPIP), the July 2010 Executive Performance Incentive Program (July 2010 EPIP) and the 2010 Stock Incentive Award program (2010 SIA), which were paid out in Company common stock on December 31, 2012, were treated as equity awards. Awards under the 2011 Volume and Efficiency Program (2011 VEP), the 2012 Executive Performance Incentive Program (2012 EPIP), the 2012 Value Driver Award program (2012 VDA) and the EQM TR Program, which remain outstanding at December 31, 2012, 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 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 yield is based on the historical dividend yield of the Company’s common stock 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 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.

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, typically 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 historical dividend yield of the Company’s stock at the time of grant. The expected volatility is based on historical volatility of the Company’s 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 shares. 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 through 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 4 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 with major financial institutions whose creditworthiness 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, the Company sets limits related to acceptable exposure levels.

The financial instruments currently utilized by the Company are primarily 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 flow from undue exposure to the risk of changing commodity prices.

With respect to the derivative commodity instruments held by the Company for purposes other than trading as of December 31, 2012 and 2011, 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 356 Bcf and 347 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."

A hypothetical decrease of 10% in the market price of natural gas from the December 31, 2012 and 2011 levels would increase the fair value of non-trading natural gas derivative instruments by approximately $131.0 million and $129.1 million, respectively. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2012 and 2011 levels would decrease the fair value of non-trading natural gas derivative instruments by approximately $130.2 million and $128.1 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, 2012.

The price change was then applied to the non-trading 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 for purposes other than trading 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 for risk management purposes approximates the notional quantity of a portion of the expected or committed transaction volume of physical commodities with commodity price risk for the same time periods. Furthermore, the derivative commodity instrument portfolio is managed to complement the physical transaction portfolio, reducing overall risks within limits. Therefore, an adverse impact to the fair value of the portfolio of derivative commodity instruments held for risk management purposes associated with the hypothetical changes in commodity prices referenced above should be offset by a favorable impact on the underlying hedged physical transactions, 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 and the anticipated transactions occur as expected.

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 12 and 13 to the Consolidated Financial Statements for further discussion of the Company's borrowings and Note 5 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 the 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, collar and option 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. This includes monitoring market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits. To manage the level of credit risk, the Company enters into transactions with financial counterparties that are of investment grade, enters into netting agreements whenever possible and may obtain collateral or other security.

Approximately 80%, or $303.0 million, of the Company's OTC derivative contracts outstanding at December 31, 2012 had a positive fair value. Approximately 81%, or $508.5 million of the Company's OTC derivative contracts at December 31, 2011 had a positive fair value.

As of December 31, 2012, the Company was not in default under any derivative contracts and has no knowledge of default by any counterparty to derivative contracts. During 2012, 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 will continue to monitor 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 area and a gas processor in Kentucky. 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 has 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, 2012, 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.

The Partnership has 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 borrowing by the Partnership. As of December 31, 2012, the Partnership had no letters of credit and no loans outstanding under the revolving 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.

Item 8. Financial Statements and Supplementary Data

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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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), the effectiveness of EQT Corporation and Subsidiaries' internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2013, expressed an unqualified opinion thereon.

Ernst & Young LLP

Pittsburgh, Pennsylvania
February 21, 2013

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, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2012, 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, 2012 and 2011, 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, 2012 and our report dated February 21, 2013 expressed an unqualified opinion thereon.

Ernst + Young LLP

Pittsburgh, Pennsylvania
February 21, 2013

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME
YEARS ENDED DECEMBER 31,

	2012	2011	2010
	(Thousands except per share amounts)		
Operating revenues	$ 1,641,608	$ 1,639,934	$ 1,374,395
Operating expenses:			
Purchased gas costs	228,405	256,467	252,884
Operation and maintenance	141,935	127,642	152,414
Production	96,155	80,911	67,414
Exploration	10,370	4,932	5,368
Selling, general and administrative	195,097	172,294	155,551
Depreciation, depletion and amortization	499,118	339,297	270,285
Total operating expenses	1,171,080	981,543	903,916
Gain on dispositions	–	202,928	–
Operating income	470,528	861,319	470,479
Other income	15,965	34,138	12,898
Interest expense	184,786	136,328	128,157
Income before income taxes	301,707	759,129	355,220
Income taxes	105,296	279,360	127,520
Net income	196,411	479,769	227,700
Less: Net income attributable to noncontrolling interests	13,016	–	–
Net income attributable to EQT Corporation	$ 183,395	$ 479,769	$ 227,700
Earnings per share of common stock attributable to EQT Corporation:			
Basic:			
Net income	$ 1.23	$ 3.21	$ 1.58
Diluted:			
Net income	$ 1.22	$ 3.19	$ 1.57

See notes to consolidated financial statements.

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
YEARS ENDED DECEMBER 31,

	2012	2011	2010
		(Thousands)	
Net income	$ 196,411	$ 479,769	$ 227,700
Other comprehensive (loss) income, net of tax:			
Net change in cash flow hedges:			
Natural gas, net of tax (benefit) expense of ($61,757), $110,186 and $30,047	(93,878)	166,840	49,601
Interest rate, net of tax expense (benefit) of $4,833, ($5,720) and $0	6,369	(7,433)	116
Unrealized (loss) gain on available-for-sale securities	–	(4,896)	806
Pension and other post-retirement benefits liability adjustment, net of tax (benefit) expense of ($1,992), ($2,752) and $1,331	(1,085)	(4,474)	2,021
Other comprehensive (loss) income	(88,594)	150,037	52,544
Comprehensive income	107,817	629,806	280,244
Less: Comprehensive income attributable to noncontrolling interests	13,016	–	–
Comprehensive income attributable to EQT Corporation	$ 94,801	$ 629,806	$ 280,244

See notes to consolidated financial statements.

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS
YEARS ENDED DECEMBER 31,

	2012	2011	2010
		(Thousands)	
Cash flows from operating activities:			
Net income	$ 196,411	$ 479,769	$ 227,700
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income taxes	95,185	234,019	153,912
Depreciation, depletion and amortization	499,118	339,297	270,285
Gain on dispositions	–	(202,928)	–
(Recoveries of) provisions for losses on accounts receivable	(1,235)	1,581	5,134
Other income	(15,965)	(34,138)	(12,898)
Stock-based compensation expense	40,230	20,080	14,104
Unrealized losses (gains) on derivatives and inventory	7,182	(1,497)	(4,702)
Lease impairment	5,543	2,587	263
Noncash financial instrument put premium	8,227	–	–
Storage reserve adjustment	(2,508)	–	–
Reimbursements for tenant improvements	–	–	4,053
Changes in other assets and liabilities:			
Dividend from Nora Gathering, LLC	12,750	23,500	–
Accounts receivable and unbilled revenues	(48,364)	14,317	(6,330)
Inventory	43,277	1,117	45,104
Prepaid expenses and other	(17,404)	22,812	126,042
Accounts payable	32,275	42,262	(36,853)
Other current liabilities	(22,864)	(15,054)	(2,963)
Other items, net	(10,991)	(12,460)	6,889
Net cash provided by operating activities	820,867	915,264	789,740
Cash flows from investing activities:			
Capital expenditures	(1,399,385)	(1,274,280)	(1,246,932)
Tenant improvements	–	–	(4,053)
Proceeds from sale of available-for-sale securities	–	29,947	12,306
Proceeds from sale of assets	4,842	619,999	–
Investment in available-for-sale securities	–	–	(750)
Net cash used in investing activities	(1,394,543)	(624,334)	(1,239,429)
Cash flows from financing activities:			
Proceeds from the issuance of common units of EQT Midstream Partners, LP, net of issuance costs	276,780	–	–
Dividends paid	(131,803)	(131,625)	(127,292)
Distributions to noncontrolling interests	(5,031)	–	–
Proceeds from issuance of common stock	–	–	537,206
Proceeds from issuance of long-term debt	–	750,000	–
Debt issuance costs and revolving credit facility origination fees	(4,022)	(11,738)	(10,962)
(Decrease) increase in short-term loans	–	(53,650)	48,650
Repayments and retirements of long-term debt	(219,315)	(15,457)	–
Proceeds and tax benefits from exercises under employee compensation plans	7,871	2,791	2,087
Net cash (used in) provided by financing activities	(75,520)	540,321	449,689
Net change in cash and cash equivalents	(649,196)	831,251	–
Cash and cash equivalents at beginning of year	831,251	–	–
Cash and cash equivalents at end of year	$ 182,055	$ 831,251	$ –
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$ 187,884	$ 129,486	$ 127,904
Income taxes, net	$ 27,605	$ 47,242	$ (129,495)

See notes to consolidated financial statements.

EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2012	2011
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 182,055	$ 831,251
Accounts receivable (less accumulated provision for doubtful accounts: $12,586 in 2012; $16,371 in 2011)	205,479	153,321
Unbilled revenues	27,699	30,257
Inventory	76,787	123,960
Derivative instruments, at fair value	304,237	512,161
Prepaid expenses and other	56,588	39,184
Total current assets	852,845	1,690,134
Equity in nonconsolidated investments	130,368	136,972
Property, plant and equipment	10,139,903	8,768,713
Less: accumulated depreciation and depletion	2,424,605	1,962,404
Net property, plant and equipment	7,715,298	6,806,309
Regulatory assets	111,915	94,095
Other assets	39,436	45,209
Total assets	$ 8,849,862	$ 8,772,719

See notes to consolidated financial statements.

EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2012	2011
	(Thousands)	
Liabilities and Stockholders' Equity		
Current liabilities:		
Current portion of long-term debt	$ 23,204	$ 219,315
Accounts payable	289,032	256,757
Derivative instruments, at fair value	75,562	123,306
Other current liabilities	182,667	205,532
Total current liabilities	570,465	804,910
Long-term debt	2,502,969	2,527,627
Deferred income taxes and investment tax credits	1,666,029	1,618,944
Pension and other post-retirement benefits	49,023	47,589
Other credits	172,574	179,819
Total liabilities	4,961,060	5,178,889
Equity:		
Stockholders' equity		
Common stock, no par value, authorized 320,000 shares, shares issued: 175,684 in 2012 and 2011	1,770,545	1,734,994
Treasury stock, shares at cost: 25,575 in 2012 and 26,207 in 2011	(461,774)	(473,215)
Retained earnings	2,195,502	2,143,910
Accumulated other comprehensive income	99,547	188,141
Total common stockholders' equity	3,603,820	3,593,830
Noncontrolling interests in consolidated subsidiaries	284,982	–
Total equity	3,888,802	3,593,830
Total liabilities and equity	$ 8,849,862	$ 8,772,719

See notes to consolidated financial statements.

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
YEARS ENDED DECEMBER 31, 2012, 2011 and 2010

	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, 2009	130,931	$ 470,112	$ 1,695,358	$ (14,440)	$ −	$ 2,151,030
Comprehensive income (net of tax):						
Net income			227,700			227,700
Net change in cash flow hedges:						
Natural gas, net of tax of $30,047				49,601		49,601
Interest rate				116		116
Unrealized loss on available-for-sale securities				806		806
Pension and other post-retirement benefits liability adjustment, net of tax of $1,331				2,021		2,021
Dividends ($0.88 per share)			(127,292)			(127,292)
Stock-based compensation plans, net	168	6,822				6,822
Issuance of common shares	18,054	767,892				767,892
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

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

See notes to consolidated financial statements.

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 utilizes the equity method of accounting for companies where its ownership is less than or equal to 50% and significant influence exists. EQT owns a 2.0% general partner interest, all incentive distribution rights and a 57.4% limited partner interest in the 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.

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 three 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. Distribution's operations primarily comprise the state-regulated natural gas distribution activities of the Company.

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.

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 inventory hedged under cash flow hedges, the Company reclassifies unrealized hedge amounts deferred in accumulated other comprehensive income into earnings in the same period as the related inventory is sold or a lower of cost or market adjustment is applied. 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, 2012, 2011 and 2010, the Company recorded losses for lower of cost or market adjustments of $7.0 million, $7.2 million and $1.3 million, respectively, which became part of the average cost of the inventory.

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

	December 31, 2012	December 31, 2011
	(Thousands)	
Oil and gas producing properties, successful efforts method	$ 6,750,343	$ 5,772,083
Accumulated depletion	(1,572,775)	(1,177,526)
Net oil and gas producing properties	5,177,568	4,594,557
Midstream plant	2,308,362	1,924,685
Accumulated depreciation and amortization	(483,358)	(424,963)
Net midstream plant	1,825,004	1,499,722
Distribution plant	986,470	980,793
Accumulated depreciation and amortization	(328,859)	(325,836)
Net distribution plant	657,611	654,957
Other properties, at cost less accumulated depreciation	55,115	57,073
Net property, plant and equipment	$ 7,715,298	$ 6,806,309

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 $72.1 million, $69.3 million and $56.8 million in 2012, 2011 and 2010, respectively. The Company capitalized $15.6 million, $13.3 million and $7.6 million of interest relative to Marcellus well development in 2012, 2011 and 2010, 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 natural gas producing properties consist of gas producing properties which were depleted at an overall average rate of $1.54/Mcfe, $1.25/Mcfe and $1.26/Mcfe produced for the years ended December 31, 2012, 2011 and 2010, 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 proved 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 proved 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, 2012, 2011 and 2010, the Company did not recognize impairment charges on proved oil and gas properties.

Capitalized costs of unproved properties are evaluated for recoverability on a prospect 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. Unproved properties had a net book value of $385.6 million and $358.8 million at December 31, 2012 and 2011, respectively. Unproved property impairments primarily as a result of lease expirations prior to drilling of $5.5 million, $2.6 million and $0.3 million are included in exploration expense for the years ended December 31, 2012, 2011 and 2010, respectively.

The Company had capitalized exploratory well costs pending the determination of proved reserves of $6.9 million on an exploratory Utica well in Pennsylvania at December 31, 2008. During 2009, the Company incurred $1.0 million on this well and then made the decision to plug back the well and convert it to a horizontal Marcellus well in 2010. As a result, the Company wrote-off $2.9 million of incremental costs related to drilling in the Utica formation in 2010. At December 31, 2012 and 2011, the Company had no capitalized exploratory well costs.

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).

Distribution property, plant and equipment, all regulated property, is carried at cost. Depreciation is recorded using composite rates on a straight-line basis. The overall rate of depreciation for the years ended December 31, 2012 and 2011 was approximately 4%.

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 and state-regulated gathering operations. The Distribution segment's rates, terms of service and contracts with affiliates are subject to comprehensive regulation by the Pennsylvania Public Utility Commission (PA PUC) and the West Virginia Public Service Commission (WV PSC). The issuance of securities by Equitable Gas Company, LLC, the Company's gas distribution subsidiary, is also subject to regulation by the PA PUC and WV PSC. Distribution also provides field line service, also referred to as "farm tap" service, in Kentucky, which is subject only to rate regulation by the Kentucky Public Service Commission (KY PSC). 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.

Where permitted by regulatory authority under purchased natural gas adjustment clauses or similar tariff provisions, Distribution defers the difference between its purchased natural gas cost, less refunds, and the billing of such cost. The deferred amount is amortized over subsequent periods in which billings either recover or refund such amounts. Such amounts are reflected in the Company's Consolidated Balance Sheets as other current assets or liabilities. For further information regarding regulatory assets, see Note 11.

The following table presents the total regulated net revenues and operating expenses of the Company:

	Years Ended December 31, 2012	2011	2010
		(Thousands)	
Distribution revenues	$ 301,260	$ 380,960	$ 411,978
Midstream revenues	136,995	125,872	124,958
Total regulated revenues	$ 438,255	$ 506,832	$ 536,936
Distribution purchased gas costs	$ 136,029	$ 199,381	$ 231,407
Midstream purchased gas costs	3,784	6,303	4,930
Total regulated purchased gas costs	$ 139,813	$ 205,684	$ 236,337
Distribution net revenues	$ 165,231	$ 181,579	$ 180,571
Midstream net revenues	133,211	119,569	120,028
Total regulated net revenues	$ 298,442	$ 301,148	$ 300,599
Distribution operating expenses	$ 100,790	$ 100,205	$ 103,915
Midstream operating expenses	66,839	69,944	65,029
Total regulated operating expenses	$ 167,629	$ 170,149	$ 168,944

The following table presents the regulated net property, plant and equipment of the Company:

	As of December 31, 2012	2011
	(Thousands)	
Distribution property, plant & equipment	$ 986,470	$ 980,793
Accumulated depreciation and amortization	(328,859)	(325,836)
Net Distribution property, plant & equipment	657,611	654,957
Midstream property, plant & equipment	795,498	604,867
Accumulated depreciation and amortization	(148,212)	(137,339)
Net Midstream property, plant & equipment	647,286	467,528
Total net regulated property, plant & equipment	$ 1,304,897	$ 1,122,485

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 comprised of the president and chief executive officer, the chief financial officer and other officers and employees.

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 for trading purposes and (ii) interest rate swap agreements to hedge exposures to fluctuations in interest rates. At contract inception, the Company designates its derivative instruments as hedging or trading activities.

The Company recognizes all derivative instruments as either current assets or current liabilities at fair value due to their highly liquid nature. The Company can net settle its derivative instruments at any time. The measurement of fair value is based upon actively quoted market prices when available. In the absence of actively quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based upon valuation methodologies deemed appropriate by the Company's CRC.

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, 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 has elected to exclude the spot/forward differential from the assessment of effectiveness of the 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 other comprehensive income 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 other comprehensive income 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 (AFUDC)*:* 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 PA PUC, the WV PSC or 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 $3.9 million, $2.2 million and $1.1 million for the years ended December 31, 2012, 2011 and 2010, 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 $6.9 million, $4.0 million and $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Capitalized Interest: Interest costs for the construction of certain long-term assets in unregulated Company businesses are capitalized and amortized over the related assets' estimated useful lives. The Company capitalized interest costs of $15.7 million, $13.3 million and $8.2 million during 2012, 2011 and 2010, respectively, as a portion of the cost of the related long-term assets.

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 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, 2012 and 2011 are detailed below.

	December 31,	
	2012	2011
	(Thousands)	
Incentive compensation	$ 52,291	$ 84,771
Taxes other than income	37,048	22,075
Accrued customer credits	32,376	31,857
Accrued interest payable	29,878	32,976
All other accrued liabilities	31,074	33,853
Total other current liabilities	$ 182,667	$ 205,532

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. Sales of natural gas to Distribution customers are billed on a monthly cycle basis; however, the billing cycles for certain customers do not coincide with accounting periods used for financial reporting purposes. The Company follows the revenue accrual method of accounting for Distribution segment revenue whereby revenues applicable to gas delivered to customers but not yet billed under the cycle billing method are estimated and accrued and the related costs are charged to expense. 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 mark-to-market 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 and are recorded using mark-to-market accounting. Revenues associated with the Company's natural gas advance sales contracts are recognized as natural gas is gathered and delivered. 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: 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.

Other investments in equity securities which are generally under 20% ownership and where the Company does not exert significant influence over operating and financial policies are accounted for as available-for-sale and are classified as investments, available-for-sale on the Consolidated Balance Sheets. Available-for-sale securities are required to be carried at fair value, with any unrealized gains and losses reported on the Consolidated Balance Sheets within a separate component of equity, accumulated other comprehensive income. The Company utilizes the average cost method to determine the cost of the securities. The Company regularly reviews its available-for-sale securities to determine whether a decline in fair value below the cost basis is other than temporary. If the decline in fair value is judged to be other than temporary, the cost basis of the security is written down to fair value and the amount of the write-down is included in the Statements of Consolidated Income.

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 other comprehensive income. 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 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 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. Where deferred tax liabilities will be passed through to customers in regulated rates, the Company establishes a corresponding regulatory asset for the increase in future revenues that will result when the temporary differences reverse.

Investment tax credits realized in prior years were deferred and are being amortized over the estimated service lives of the related properties where required by ratemaking rules.

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 drilled. 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 following table presents a reconciliation of the beginning and ending carrying amounts of the Company's asset retirement obligations which are included in other 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,	
	2012	2011
	(Thousands)	
Asset retirement obligation as of beginning of period	$ 104,760	$ 66,315
Accretion expense	7,716	5,032
Liabilities incurred	1,141	878
Liabilities settled	(2,408)	(1,316)
Revisions in estimated cash flows	(430)	33,851
Asset retirement obligation as of end of period	$ 110,779	$ 104,760

In 2011, EQT Production performed a review of the assumptions used to calculate its current asset retirement obligation and increased the obligation primarily as a result of an increase in the assumed inflation rate.

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 or fluctuations in premiums, differ from estimates.

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

	December 31,	
	2012	2011
	(Thousands)	
Net unrealized gain from natural gas hedging transactions	$ 138,188	$ 232,066
Net unrealized loss from interest rate swaps	(1,276)	(7,645)
Pension and other post-retirement benefits liability adjustment	(37,365)	(36,280)
Accumulated other comprehensive income	$ 99,547	$ 188,141

Noncontrolling interest: Noncontrolling interests represent third-party equity ownership in certain of our consolidated subsidiaries and are presented as a component of equity. See Note 2 for further discussion of noncontrolling interests related to the Partnership.

Recently Issued Accounting Standards:

Disclosures about Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board (FASB) issued a standard update intended to enhance disclosures required by requiring additional information about financial instruments and derivative instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement. The update is to be applied prospectively and is effective for annual reporting periods beginning on or after January 1, 2013. The Company is currently evaluating the impact this standard will have on its financial statement disclosures.

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

2. 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, LP (Equitrans, the Company's FERC-regulated transmission, storage and gathering subsidiary). An indirect wholly-owned subsidiary of EQT serves as the general partner of the Partnership, and the Company continues to operate the Equitrans business pursuant to the contractual arrangements set forth below. The Company continues to consolidate the results of the Partnership but records an income tax provision only as to its ownership percentage. EQT records the noncontrolling interest of the public limited partners in EQT's financial statements.

Also, in connection with the closing of the IPO:

- The Partnership, its general partner and EQT entered into an Omnibus Agreement (Omnibus Agreement), pursuant to which, among other things, EQT 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 EQT and the Partnership.

- EQT's 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, 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.

- 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 will 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 share-based 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 closing of the IPO, which increased the noncontrolling interest component of total equity. Approximately $231 million of the proceeds were distributed to EQT, $12 million was retained by the Partnership to replenish amounts distributed by Equitrans to EQT 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 revolving credit facility origination fees associated with the revolving credit agreement entered into by the Partnership at the closing of the IPO.

The Partnership paid distributions of $5.0 million to noncontrolling interests at $0.35 per common unit during 2012.

3. 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.

The Company's management reviews and reports the EQT Production segment results with third-party transportation costs reflected as a deduction from operating revenues. During 2011, because of increased materiality of these costs, the Company determined that consolidated results are required to be reported on a gross basis with third-party transportation costs recorded as a portion of purchased gas costs in the Consolidated Statement of Income. The consolidated operating revenues, purchased gas costs and total operating expenses for all periods presented have been adjusted to reflect this gross presentation. This adjustment had no impact on consolidated net income, consolidated operating income or the segment results for any period presented. Management believes this adjustment is not material to the overall financial statement presentation.

	Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
Revenues from external customers:			
EQT Production	$ 793,773	$ 791,285	$ 537,657
EQT Midstream	505,498	525,345	580,698
Distribution	313,990	419,678	474,143
Third-party transportation costs (a)	126,783	87,034	51,687
Less intersegment revenues, net (b)	(98,436)	(183,408)	(269,790)
Total	$ 1,641,608	$ 1,639,934	$ 1,374,395
Operating income:			
EQT Production	$ 187,913	$ 387,098	$ 223,487
EQT Midstream (c)	237,324	416,611	178,866
Distribution	68,614	86,898	83,182
Unallocated expenses (d)	(23,323)	(29,288)	(15,056)
Total operating income	$ 470,528	$ 861,319	$ 470,479

Reconciliation of operating income to net income:

Other income	$ 15,965	$ 34,138	$ 12,898
Interest expense	184,786	136,328	128,157
Income taxes	105,296	279,360	127,520
Net income	$ 196,411	$ 479,769	$ 227,700

	As of December 31,	
	2012	2011
	(Thousands)	
Segment assets:		
EQT Production	$ 5,675,534	$ 5,256,645
EQT Midstream	2,046,558	1,785,089
Distribution	860,029	850,414
Total operating segments	8,582,121	7,892,148
Headquarters assets, including cash and short-term investments	267,741	880,571
Total assets	$ 8,849,862	$ 8,772,719

(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 and transportation activities between EQT Midstream and both EQT Production and Distribution. Reduced activity between segments and lower prices caused the changes from 2012 to 2011 and 2011 to 2010.

(c) Gains on dispositions of $202.9 million are included in EQT Midstream operating income for 2011. See Note 6.

(d) Unallocated expenses consist primarily of incentive compensation, administrative costs and $4.5 million of expenses related to the pending sale of Equitable Gas and Homeworks that are not allocated to the operating segments.

	Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
Depreciation, depletion and amortization:			
EQT Production	$ 409,628	$ 257,144	$ 183,699
EQT Midstream	64,782	57,135	61,863
Distribution	24,454	25,747	24,174
Other	254	(729)	549
Total	$ 499,118	$ 339,297	$ 270,285
Expenditures for segment assets:			
EQT Production (e)	$ 991,775	$ 1,087,840	$ 1,245,914
EQT Midstream	375,731	242,886	193,128
Distribution	28,745	31,313	36,619
Other	3,134	4,855	1,958
Total	$ 1,399,385	$ 1,366,894	$ 1,477,619

(e) Expenditures for segment assets in the EQT Production segment include $134.6 million, $57.2 million and $357.7 million for undeveloped property acquisitions in 2012, 2011 and 2010, 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 discussed in Note 7, in 2011 and $230.7 million of undeveloped property which was acquired with EQT common stock in 2010.

4. 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 through 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 derivative commodity instruments that are purchased from or placed with major financial institutions whose creditworthiness is regularly monitored. Futures contracts 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 also engages 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. 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, 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.

For a derivative instrument that has been designated and qualifies as a fair value hedge, the change in the fair value of 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 has elected to exclude the spot/forward differential for the assessment of effectiveness of the fair value hedges. 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.

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.

Some 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. 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 have been designated and qualify as fair value hedges.

In addition, the Company enters into a limited number of energy trading contracts to leverage its assets and limit its exposure to shifts in market prices and has a limited number of other derivative instruments not designated as hedges. In 2008 and 2011, the Company effectively settled certain derivative commodity swaps scheduled to mature during the period 2010 through 2013 by de-designating the instruments and entering into directly counteractive instruments. These transactions resulted in offsetting positions which are the majority of the derivative asset and liability balances not designated as hedging instruments.

All derivative instrument 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.

	Years Ended December 31, 2012	2011	2010
		(Thousands)	
Commodity derivatives designated as cash flow hedges			
Amount of gain recognized in other comprehensive income (OCI) (effective portion), net of tax	$ 86,259	$ 239,019	$ 113,320
Amount of gain reclassified from accumulated OCI into operating revenues (effective portion), net of tax	180,137	72,179	63,719
Amount of (loss) gain recognized in operating revenues (ineffective portion) (a)	(75)	(181)	3,046
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)	(241)	(140)	(116)
Commodity derivatives designated as fair value hedges (b)			
Amount of gain recognized in operating revenues for fair value commodity contracts	$ 3,878	$ 12,263	$ –
Fair value gain (loss) recognized in operating revenues for inventory designated as hedged item	3,292	(6,059)	–
Derivatives not designated as hedging instruments			
Amount of gain recognized in operating revenues	$ 2,176	$ 4,209	$ 369

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

(b) 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.

	December 31, 2012	2011
	(Thousands)	
Asset derivatives		
Commodity derivatives designated as hedging instruments	$ 259,459	$ 412,626
Commodity derivatives not designated as hedging instruments	44,778	99,535
Total asset derivatives	$ 304,237	$ 512,161
Liability derivatives		
Commodity derivatives designated as hedging instruments	$ 27,946	$ 3,681
Interest rate derivatives designated as hedging instruments	–	10,861
Commodity derivatives not designated as hedging instruments	47,616	108,764
Total liability derivatives	$ 75,562	$ 123,306

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 commodity derivative instruments changed during 2012 primarily as a result of settlements and increased commodity prices. The absolute quantities of the Company's derivative commodity instruments that have been designated and qualify as cash flow hedges totaled 365 Bcf and 349 Bcf as of December 31, 2012 and December 31, 2011, respectively, and are primarily related to natural gas swaps and collars. The open positions at December 31, 2012 had maturities extending through December 2017. The absolute quantities of the Company's derivative commodity instruments that have been designated and qualify as fair value hedges totaled 8 Bcf and 9 Bcf as of December 31, 2012 and December 31, 2011, respectively.

The Company deferred net gains of $138.2 million and $232.1 million in accumulated OCI, net of tax, as of December 31, 2012 and 2011, 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 $87.5 million of net unrealized gains on its derivative commodity instruments reflected in accumulated other comprehensive income, net of tax, as of December 31, 2012 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 during 2010 and 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 the reduction of EQT Production segment operating revenue by $8.2 million, the increase of accumulated other comprehensive income by $5.1 million and the decrease of deferred tax expense by $3.1 million. The Company concluded that this error is not material to any prior periods, the 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 New York Mercantile Exchange (NYMEX) traded futures contracts have reduced credit risk because Commodity Futures Trading Commission 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.

The Company utilizes various processes and analysis to monitor and evaluate its credit risk exposures. These include closely monitoring current market conditions 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 deals 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, 2012 and 2011.

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. Participants 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 a current asset of $0.7 million as of December 31, 2012 and a current asset of $0.1 million as of December 31, 2011 for such deposits in its Consolidated Balance Sheets.

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, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $4.0 million, for which the Company had no collateral posted on December 31, 2012. If the Company's credit rating by S&P or Moody's had been downgraded below investment grade on December 31, 2012, the Company would have been required to post additional collateral of $1.4 million in respect of the liability position. 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 Baa2 by Moody's at December 31, 2012. 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.

5. 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. Assets and liabilities in Level 3 include the Company's collars and a limited number of the Company's swap agreements. Since the adoption of fair value accounting, the Company has not made any changes to its classification of assets and liabilities in each category.

The fair value of 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. Collars included in Level 3 are valued using standard industry income approach models. The primary significant unobservable input to the valuation of assets and liabilities in Level 3 is the volatility assumption to the option pricing model used to value commodity collars. The Corporate Risk Control Group (CRCG), which reports to the

Chief Financial Officer, is responsible for calculating the volatilities. The CRCG considers current market information about option trading and historical averages. The Company prepares an analytical review of all derivative instruments for reasonableness on at least a quarterly basis. At December 31, 2012, the range of Company derived market volatilities used to value Level 3 assets and liabilities was 24 – 37%. The fair value of the collar agreements is sensitive to changes in the volatility assumption. Significant changes in this assumption might result in significantly higher or lower fair values for these assets and liabilities. As of December 31, 2012, an increase in the volatility assumption would increase the value of the derivative asset and a decrease in the volatility assumption would decrease the value of the derivative asset. 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 period:

		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

		Fair value measurements at reporting date using		
Description	**December 31, 2011**	**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	$ 512,161	$ 3,612	$ 365,238	$ 143,311
Liabilities				
Derivative instruments, at fair value	$ 123,306	$ 2,727	$ 120,528	$ 51

	Fair value measurements using significant unobservable inputs (Level 3) Derivative instruments, at fair value, net Years Ended December 31,	
	2012	2011
	(Thousands)	
Balance at January 1	$ 143,260	$ 116,672
Total gains or losses:		
Included in earnings	(615)	14
Included in other comprehensive income	23,386	81,825
Purchases	(933)	–
Settlements	(74,384)	(55,251)
Transfers in and/or out of Level 3	–	–
Balance at December 31	$ 90,714	$ 143,260

There are 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 still held as of December 31, 2012 and 2011.

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. 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, 2012 and 2011 was approximately $2.9 billion and $3.0 billion, respectively.

For information on the fair value of the defined benefit pension plan assets, see Note 14.

6. Proposed Sale of Properties and Sales of Properties

On December 19, 2012, the Company and its direct wholly-owned subsidiary, Distribution Holdco, LLC (Holdco), executed a definitive agreement (the Master Purchase Agreement) with PNG Companies LLC (PNG Companies), the parent company of Peoples Natural Gas Company LLC (Peoples), pursuant to which EQT and Holdco will transfer 100% of their ownership interests of Equitable Gas Company, LLC (Equitable Gas) and Equitable Homeworks, LLC (Homeworks) to PNG Companies in exchange for cash and other assets of, and new commercial arrangements with, PNG Companies and its affiliates. Homeworks and Equitable Gas are direct wholly-owned subsidiaries of Holdco. Peoples is a portfolio company of SteelRiver Infrastructure Partners. The transaction (or portions thereof) requires the approval of the PA PUC, the WV PSC, the KY PSC and the FERC. In addition, the transaction is subject to review under the Hart-Scott-Rodino Act. The agreements provide that such approvals and review must be complete by December 19, 2013, subject to certain extension rights. These approvals and review may not be received or completed within the time allowed. As a result, the Company has not classified Equitable Gas and Homeworks as held for sale in its financial statements as of December 31, 2012 and will not do so until the Company makes satisfactory progress in the regulatory process.

In connection with this transaction, EQT will receive the following assets from, and will enter into the following commercial arrangements with, PNG Companies, Peoples and Peoples TWP LLC:

- *Cash*. PNG Companies will pay $720 million in cash to EQT at the closing of the transaction, subject to certain closing and post-closing adjustments.

- *Assets*. At the closing of the transaction, Peoples will transfer certain natural gas midstream assets (the Midstream Assets) to EQT, including certain equipment upgrades to be completed by Peoples prior to closing. The parties intend to treat this transaction as a like-kind exchange for U.S. federal income tax purposes in accordance with Section 1031 of the Internal Revenue Code.

- *Commercial arrangements*. Simultaneously with the execution of the Master Purchase Agreement, EQT (or, where applicable, affiliates of EQT) and Peoples (or, where applicable, affiliates of Peoples) entered or agreed to enter into a suite of commercial agreements, including, but not limited to, gas transportation agreements, gas transportation and storage agreements and a gas purchase and sales agreement, pursuant to which EQT will provide gas transmission and storage services and supply natural gas to Peoples. At the closing of the transaction, EQT (or, where applicable, affiliates of EQT) and Peoples (or, where applicable, affiliates of Peoples) will, among other things, (i) enter into a gas purchase and sales agreement pursuant to which EQT will supply natural gas to Equitable Gas, (ii) extend the term of existing gas transportation and storage agreements pursuant to which EQT provides gas transportation and storage services to Equitable Gas and (iii) enter into a transition services agreement.

The Company incurred $4.5 million in expenses related to the pending sale of Equitable Gas and Homeworks in 2012.

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.

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.

7. Acquisitions

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 GAAP, the ANPI transaction was a business combination achieved in stages because EQT 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 was included in other income in the second quarter of 2011 on the Statements of

Consolidated 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.

This transaction also resulted in the elimination of certain previously disclosed relationships including the Company's non-controlling interest in the trust, the Company's liquidity reserve guarantee to ANPI, the Company's agreement with the trust to provide gathering and operating services to deliver its gas to market and the marketing fee the Company received for the sale of the trust's gas based on the net revenue for gas delivered.

8. Income Taxes

Income tax expense (benefit) is summarized as follows:

	Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
Current:			
Federal	$ 10,895	$ 39,867	$ (25,377)
State	(310)	6,076	(388)
Subtotal	10,585	45,943	(25,765)
Deferred:			
Federal	77,232	202,392	132,161
State	17,953	31,627	21,751
Subtotal	95,185	234,019	153,912
Amortization of deferred investment tax credit	(474)	(602)	(627)
Total	$ 105,296	$ 279,360	$ 127,520

The current income tax expense recorded in 2012 primarily related to alternative minimum tax (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 current federal tax benefit recorded in 2010 primarily related to additional cash refunds received related to the 2009 tax net operating loss carrybacks.

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.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (2010 Tax Relief Act) extended the R&E tax credit for 2010 and 2011 and increased bonus depreciation from 50% to 100% for qualified investments made after September 8, 2010 and before January 1, 2012. The 2010 Tax Relief Act also extended the 50% bonus depreciation for property placed in service after December 31, 2011 and before January 1, 2013.

The Company carried back its 2009 tax net operating loss under 2009 legislation allowing a five-year carryback of net operating losses, and received a refund of $123.4 million in 2010. The Company generated net operating losses 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. The Company expects to continue to generate tax losses over the next several years as it continues its drilling program in

Appalachia. IDC's, however, are sometimes limited for AMT purposes which can result in the Company paying AMT even when generating a regular tax NOL.

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

	Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
Tax at statutory rate	$ 105,597	$ 265,695	$ 124,327
State income taxes	9,269	25,416	14,585
Federal tax credits and incentives	(439)	(660)	(600)
Regulatory basis differences	(779)	(1,251)	(2,713)
Permanent basis differences	(3,160)	(2,411)	(1,258)
Noncontrolling partners' share of Partnership earnings	(4,571)	–	–
Other	(621)	(7,429)	(6,821)
Income tax expense	$ 105,296	$ 279,360	$ 127,520
Effective tax rate	34.9%	36.8%	35.9%

The Company's effective tax rate for the year ended December 31, 2012 was 34.9% compared to 36.8% 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 the impact of the Partnership's IPO. The effective tax rate is impacted by the recent IPO which modified the Midstream ownership structure and now reflects Partnership earnings for which the noncontrolling public limited partners are directly responsible for the related income taxes. The Company consolidates the pre-tax income related to the noncontrolling public limited partners' share of partnership earnings but excludes the related tax provision. 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's effective tax rate for the year ended December 31, 2011 was 36.8% compared to 35.9% for the year ended December 31, 2010. The increase in the rate from 2010 to 2011 was partly a result of a higher tax benefit for repair costs in 2010 than in 2011. In addition, state income taxes were higher due to a shift in the Company's non-regulated business to states with higher income tax rates. Other rate reconciling items had a larger percentage impact on the effective tax rate in 2010 than 2011 due to significantly higher pre-tax income in 2011.

In December 2011, the Internal Revenue Service (IRS) issued temporary and proposed regulations related to costs incurred in years beginning after 2011 for the repair or replacement of tangible personal property. Additional guidance is expected from the IRS regarding the implementation of these regulations. Adoption of these regulations should not have a material impact on the Company's financial statements.

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

	2012	2011	2010
		(Thousands)	
Balance at January 1	$ 30,730	$ 37,943	$ 40,726
Additions based on tax positions related to current year	2,165	1,245	2,524
Additions for tax positions of prior years	2,320	184	3,391
Settlements	–	–	–
Reductions for tax positions of prior years	(12,235)	(7,886)	(4,618)
Lapse of statute of limitations	(5,122)	(756)	(4,080)
Balance at December 31	$ 17,858	$ 30,730	$ 37,943

Included in the tabular reconciliation above at December 31, 2012, 2011 and 2010 are $6.4 million, $15.9 million and $21.2 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, other than interest and penalties, 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. Uncertain tax positions of $14.6 million and $19.4 million for the periods ending December 31, 2012 and 2011, respectively, are recorded in the Consolidated Balance Sheets as a reduction of the deferred tax asset for net operating loss and R&E tax credit carryforwards rather than as a portion of uncertain tax positions.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company reversed approximately $1.8 million and $9.7 million of previously recorded interest expense in 2012 and 2011, respectively, and recognized approximately $3.9 million of interest expense for the year ended December 31, 2010. Interest and penalties of $0.5 million, $2.3 million and $12.0 million was included in the balance sheet reserve at December 31, 2012, 2011 and 2010, respectively.

The total amount of unrecognized tax benefits, inclusive of interest and penalties, was $18.4 million, $33.0 million and $49.9 million as of December 31, 2012, 2011 and 2010, respectively. The total amount of unrecognized tax benefits (excluding interest and penalties) that, if recognized, would affect the effective tax rate was $5.3 million, $5.2 million and $8.9 million as of December 31, 2012, 2011 and 2010, respectively.

As of December 31, 2012, it was reasonably possible that the total amount of unrecognized tax benefits could decrease by up to $7.1 million 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.

There were no material changes to the Company’s methodology for unrecognized tax benefits during 2012. Because the Company is in a net operating loss position, the Company did not create unrecognized tax benefits for certain tax positions in 2012 and 2011; such amounts instead, reduce the net operating loss carryforward for those periods. Decreases to the unrecognized tax benefit balance during 2012 and 2011 were primarily attributable to the reversal of certain prior year tax positions related to timing differences and the related interest expense as well as the lapse of applicable statutes of limitations.

The consolidated federal income tax liability of the Company has been settled with the IRS through 2009. The Company also is the subject of various state income tax examinations. The Company believes that it is appropriately reserved for any 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:

	December 31,	
	2012	2011
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets	$ (635,902)	$ (449,888)
Total deferred income tax liabilities	2,283,670	2,038,225
Total net deferred income tax liabilities	1,647,768	1,588,337
Total deferred income tax liabilities (assets)		
Tax depreciation in excess of book depreciation	1,154,333	1,037,691
Drilling and development costs expensed for income tax reporting	934,495	836,219
Investment in Partnership	68,908	–
Accumulated other comprehensive income	62,632	120,295
Regulatory temporary differences	41,256	43,005
Deferred purchased gas cost	7,198	1,015
Investment tax credit	(1,043)	(1,467)
Uncollectible accounts	(3,768)	(3,953)
Post-retirement benefits	(7,510)	(8,140)
Incentive compensation	(12,104)	(1,324)
Deferred compensation plans	(17,850)	(10,814)
Alternative minimum tax credit carryforward	(69,901)	(65,509)
Net operating loss carryforwards	(523,726)	(337,921)
Other	14,848	(20,760)
Total (including amounts classified as current (assets) of ($15,828) and ($26,867), respectively)	$ 1,647,768	$ 1,588,337

The net deferred tax liability relating to the Company's accumulated other comprehensive income balance as of December 31, 2012 was comprised of an $88.0 million deferred tax liability related to the Company's net unrealized gain from hedging transactions, an $8.7 million deferred tax asset related to other post-retirement benefits, a $17.2 million deferred tax asset related to the Company's pension plans and a $0.9 million deferred tax asset related to interest rate swaps. The net deferred tax liability relating to the Company's accumulated other comprehensive income balance as of December 31, 2011 was comprised of a $149.8 million deferred tax liability related to the Company's net unrealized gain from hedging transactions, a $7.8 million deferred tax asset related to other post-retirement benefits, a $15.9 million deferred tax asset related to the Company's pension plans and a $5.7 million deferred tax asset related to interest rate swaps.

The Company also has a total deferred tax asset of $447.9 million at December 31, 2012 related to the federal net operating loss carryforward created in 2012, 2011 and 2010 of $169.2 million, $49.6 million and $229.1 million, respectively. The deferred tax asset has been reduced for uncertain tax positions of approximately $3.7 million and $7.5 million as of December 31, 2012 and 2011, respectively. The federal net operating loss carryforward period is 20 years and, if unused, the loss carryforward for 2012, 2011 and 2010 will expire in 2032, 2031 and 2030, 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 intangible drilling costs, the Company has generated AMT carryforwards totaling $69.9 million. 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, 2012, the Company had a deferred tax asset of $86.0 million, net of valuation allowances of $0.8 million, related to tax benefits from state net operating loss carryforwards with various expiration dates ranging from 2013 to 2032. As of December 31, 2011, the Company had a deferred tax asset of $59.1 million, net of valuation allowances of $0.8 million, related to tax benefits from state net operating loss carryforwards with various expiration dates ranging from 2012 to 2031. The deferred tax asset has been reduced for uncertain tax positions of approximately $6.5 million and $8.8 million and state-specific statutory limitations of approximately $59.5 million and $61.6 million as of December 31, 2012 and 2011, 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 net operating loss position.

9. 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, 2012	December 31, 2012	December 31, 2011
				(Thousands)	
Nora Gathering, LLC (Nora LLC)	USA	Joint	50%	$ 130,368	$ 136,972

The Company's ownership share of the earnings for 2012, 2011 and 2010 related to the total investments accounted for under the equity method was $6.1 million, $7.2 million and $9.7 million, respectively, reported in other income on the Company's Statements of Consolidated Income. Also included in its ownership share of the earnings of equity method investments for the years ended 2011 and 2010 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 7 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 2011 or 2012. EQT Midstream's investment in Nora LLC totaled $130.4 million and $137.0 million as of December 31, 2012 and 2011, respectively.

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, 2012	As of December 31, 2011
	(Thousands)	
Current assets	$ 15,966	$ 18,838
Noncurrent assets	249,347	260,286
Total assets	$ 265,313	$ 279,124
Current liabilities	$ 4,476	$ 5,210
Stockholders' equity	260,837	273,914
Total liabilities and stockholders' equity	$ 265,313	$ 279,124

Summarized Statements of Income

	Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
Revenues	$ 47,888	$ 49,772	$ 62,618
Operating expenses	35,596	35,520	41,693
Net income	$ 12,292	$ 14,252	$ 20,925

10. Investments, Available-For-Sale

During 2011 and 2010, the Company sold available-for-sale securities for proceeds of $29.9 million and $12.3 million, respectively. These sales resulted in gross realized gains of $8.5 million and $2.1 million in 2011 and 2010, respectively, of which $4.9 million and $1.4 million were reclassified from accumulated other comprehensive income.

The Company did not hold any available-for-sale securities at December 31, 2012 and 2011.

11. Regulatory Assets

The following table summarizes the Company's regulatory assets, net of amortization, as of December 31, 2012 and 2011. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of its regulatory assets.

	December 31,	
Description	2012	2011
	(Thousands)	
Deferred taxes	$ 108,429	$ 89,224
Deferred purchased gas costs	16,812	3,132
Other post-retirement benefits other than pensions	3,236	4,168
Other recoverable costs	250	703
Total regulatory assets	128,727	97,227
Amounts classified as other current assets	16,812	3,132
Total long-term regulatory assets	$ 111,915	$ 94,095

The regulatory asset associated with deferred taxes primarily represents deferred income taxes recoverable through future rates once the taxes become current. Deferred purchased gas costs are included in prepaid expenses and other in the Consolidated Balance Sheets.

The Company recognizes expenses for on-going post-retirement benefits other than pensions which are subject to recovery in approved rates. The regulatory asset for other post-retirement benefits other than pensions is expected to be recovered in rates within approximately 6 years.

As of December 31, 2012, the Company also had a regulatory liability of $2.3 million included in other current liabilities in the Consolidated Balance Sheets related to the over-recovery of costs associated with the Company's program to assist low-income customers.

The regulatory assets for deferred taxes and other post-retirement benefits do not earn a return on investment.

12. Short-Term Loans

The Company has 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.

In connection with its IPO, the Partnership entered into 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.

As of December 31, 2012 and 2011, neither the Company nor the Partnership had loans or letters of credit outstanding under their respective revolving credit facilities. Commitment fees averaging approximately 25 basis points for the year ended December 31, 2012 and 30 basis points for the year ended December 31, 2011 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 year ended December 31, 2012 to maintain credit availability under its revolving credit facility.

Neither the Company nor the Partnership had any short-term loans outstanding at any time during the year ended December 31, 2012. The maximum amount of outstanding short-term loans at any time for the Company during the year ended 2011 was $104.0 million. 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 Company's debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. The most significant default events include maintaining covenants with respect to maximum debt-to-total capitalization ratio, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company's current 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. As of December 31, 2012, the Company was in compliance with all debt covenants.

The Partnership's credit facility contains various covenants and restrictive provisions that, if not complied with, could require early payment or similar action, including a requirement 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, 2012, the Partnership was in compliance with all debt provisions and covenants.

13. Long-Term Debt

	December 31, 2012	December 31, 2011
	(Thousands)	
7.76% notes, due 2012 thru 2016	$ 32,973	$ 53,742
5.15% notes, due November 15, 2012	–	200,000
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 2013 thru 2023	30,000	30,000
7.6% Series C, due 2018	8,000	8,000
	2,526,173	2,746,942
Less debt payable within one year	23,204	219,315
Total long-term debt	$ 2,502,969	$ 2,527,627

During the fourth quarter of 2012, the Company repaid the principal balance on its 5.15% maturing notes with available cash on hand.

During the second quarter of 2011, 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 in a non-cash transaction. The premium recorded on this debt was $4.6 million and $6.1 million as of December 31, 2012 and 2011, respectively.

During the fourth quarter of 2011, the Company issued 4.88% Guaranteed Senior Notes due November 15, 2021 in the aggregate principal amount of $750 million.

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 $23.2 million in 2013, $11.2 million in 2014, $166.0 million in 2015, $3.0 million in 2016 and zero in 2017.

14. 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:

	For the Years Ended December 31,			
	2012	2011	2012	2011
	Pension Benefits		Other Benefits	
	(Thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 61,885	$ 61,452	$ 35,293	$ 34,706
Service cost	500	500	737	620
Interest cost	2,448	3,115	1,427	1,771
Amendments	(126)	–	–	–
Actuarial loss	5,733	3,842	2,656	1,602
Benefits paid	(5,571)	(5,776)	(3,858)	(3,406)
Expenses paid	(511)	(440)	–	–
Settlements	(1,088)	(808)	–	–
Benefit obligation at end of year	$ 63,270	$ 61,885	$ 36,255	$ 35,293
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 45,951	$ 48,083	$ 19	$ –
Actual gain on plan assets	5,346	599	–	–
Contributions	2,857	4,293	146	19
Benefits paid	(5,571)	(5,776)	–	–
Expenses paid	(511)	(440)	–	–
Settlements	(1,088)	(808)	–	–
Fair value of plan assets at end of year	$ 46,984	$ 45,951	$ 165	$ 19
Funded status at end of year	$ (16,286)	$ (15,934)	$ (36,090)	$ (35,274)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$ –	$ –	$ (3,353)	$ (3,619)
Noncurrent liabilities	(16,286)	(15,934)	(32,737)	(31,655)
Net amounts recognized	$ (16,286)	$ (15,934)	$ (36,090)	$ (35,274)
Amounts recognized in accumulated other comprehensive income, net of tax, consist of:				
Net loss	$ 24,634	$ 24,373	$ 14,291	$ 13,797
Net prior service (credit)	–	–	(1,560)	(1,890)
Net amount recognized	$ 24,634	$ 24,373	$ 12,731	$ 11,907

The accumulated benefit obligation for all defined benefit pension plans was $63.3 million and $61.9 million at December 31, 2012 and 2011, respectively. The Company uses a December 31 measurement date for its defined benefit pension and other post-retirement 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,					
	2012	2011	2010	2012	2011	2010
	Pension Benefits			Other Benefits		
	(Thousands)					
Components of net periodic benefit cost:						
Service cost	$ 500	$ 500	$ 600	$ 737	$ 620	$ 616
Interest cost	2,448	3,115	3,390	1,427	1,771	1,974
Expected return on plan assets	(3,712)	(4,070)	(4,289)	–	–	–
Amortization of prior service cost	–	–	–	(845)	(902)	(902)
Recognized net actuarial loss	1,880	1,471	1,323	1,671	1,605	1,652
Settlement loss and special termination benefits	725	530	569	–	–	–
Net periodic benefit cost	$ 1,841	$ 1,546	$1,593	$ 2,990	$ 3,094	$ 3,340

Under the 2006 Equitrans rate case settlement, the Company amortized post-retirement benefits other than pensions previously deferred over a five-year period ending in 2010. Currently, the Company recognizes expense for on-going post-retirement benefits other than pensions, which are subject to recovery in the approved rates. The Company amortized post-retirement benefits other than pensions previously deferred of approximately $0.7 million for the year ended December 31, 2010.

	For the Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	Pension Benefits			Other Benefits		
	(Thousands)					
Other changes in plan assets and benefit obligations recognized in other comprehensive income, net of tax:						
Net loss (gain)	$ 261	$3,378	$(1,056)	$ 494	$ 181	$ (1,246)
Net prior service cost	–	–	–	330	915	281
Total recognized in other comprehensive income, net of tax	$ 261	$3,378	$(1,056)	$ 824	$ 1,096	$ (965)
Total recognized in net periodic benefit cost and other comprehensive income, net of tax	$2,102	$4,924	$ 537	$ 3,814	$ 4,190	$ 2,375

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive income, net of tax, into net periodic benefit cost during 2013 is $1.3 million. The estimated net loss and net prior service (credit) for the other post-retirement benefit plans that will be amortized from accumulated other comprehensive income, net of tax, into net periodic benefit cost during 2013 are $0.9 million and $(0.5) 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,			
	2012	2011	2012	2011
	Pension Benefits		Other Benefits	
Discount rate	3.25%	4.25%	3.25%	4.25%
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,			
	2012	2011	2012	2011
	Pension Benefits		Other Benefits	
Discount rate	4.25%	5.50%	4.25%	5.50%
Expected return on plan assets	7.75%	8.00%	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, 2013 is 7.75%. This assumption will be used to derive the Company's 2013 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 as the expected rate of return decreases or if the discount rate is lowered.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2012 was 7.50% 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		
	2012	2011	2010	2012	2011	2010
	(Thousands)					
Increase (decrease) to total of service and interest cost components	$ 32	$ 40	$ 47	$ (32)	$ (39)	$ (46)
Increase (decrease) to post-retirement benefit obligation	$ 711	$ 730	$ 756	$ (688)	$ (702)	$ (723)

The Company's pension asset allocation at December 31, 2012 and 2011 and target allocation for 2013 by asset category are as follows:

Asset Category	Target Allocation 2013	Percentage of Plan Assets at December 31, 2012	2011
Domestic broadly diversified equity securities	40% - 60%	53%	48%
Fixed income securities	20% - 50%	32%	35%
International broadly diversified equity securities	5% - 15%	10%	9%
Alternative fixed income securities	0% - 10%	4%	4%
Cash and equivalent investments	0% - 15%	1%	4%
		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 is comprised 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 Company made cash contributions of approximately $2.9 million, $4.3 million and $1.3 million to its pension plan during 2012, 2011 and 2010, respectively, to meet certain funding targets. The Company expects to make cash payments of at least $1.8 million related to its pensions during 2013, 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: $6.2 million in 2013; $6.1 million in 2014; $5.6 million in 2015; $5.3 million in 2016; $5.4 million in 2017; and $22.4 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: $3.6 million in 2013; $3.5 million in 2014; $3.4 million in 2015; $3.3 million in 2016; $3.2 million in 2017; and $13.9 million in the five years thereafter.

Expense recognized by the Company related to its defined contribution plans totaled $12.0 million in 2012, $10.1 million in 2011 and $10.4 million in 2010.

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:

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 $8.8 million and $20.0 million as of December 31, 2012 and 2011, 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 $38.2 million and $25.9 million as of December 31, 2012 and 2011, 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, 2012 and 2011, the defined benefit plan did not hold any assets whose fair value was determined using unobservable inputs and therefore would be considered Level 3.

15. Common Stock and Earnings Per Share

At December 31, 2012, shares of EQT's authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	10,048
Total	30,505

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,		
	2012	2011	2010
	(Thousands except per share amounts)		
Basic earnings per common share:			
Net income attributable to EQT Corporation	$ 183,395	$ 479,769	$ 227,700
Average common shares outstanding	149,619	149,392	144,458
Basic earnings per common share	$ 1.23	$ 3.21	$ 1.58
Diluted earnings per common share:			
Net income attributable to EQT Corporation	$ 183,395	$ 479,769	$ 227,700
Average common shares outstanding	149,619	149,392	144,458
Potentially dilutive securities:			
Stock options and awards (a)	887	817	774
Total	150,506	150,209	145,232
Diluted earnings per common share	$ 1.22	$ 3.19	$ 1.57

(a) Options to purchase 281,528, 6,480 and 1,229,109 shares of common stock were not included in the computation of diluted earnings per common share for 2012, 2011 and 2010, respectively, because the options' exercise prices were greater than the average market price of the common shares in the applicable year. The impact of the Partnership's diluted units did not have a material impact to the Company's earnings per share calculations for any of the periods presented.

16. Share-Based Compensation Plans

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

	Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
2008 Executive Performance Incentive Program	$ –	$ 923	$ 316
2010 Executive Performance Incentive Programs	1,940	2,118	2,905
2012 Executive Performance Incentive Program	10,633	–	–
2007 Supply Long-Term Incentive Program	–	198	6,763
2010 Stock Incentive Award Program	4,022	4,241	4,134
2011 Value Driver Award Program	3,033	15,807	–
2012 Value Driver Award Program	11,557	–	–
2011 Volume and Efficiency Program	5,286	5,384	–
Restricted stock awards	2,677	2,281	3,020
Non-qualified stock options	3,580	6,057	4,045
Non-employee directors' share-based awards	2,558	3,320	1,196
EQM Long-Term Incentive Plan awards	535	–	–
Total share-based compensation expense	$ 45,821	$ 40,329	$ 22,379

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 3.

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2012, 2011 and 2010, was $7.9 million, $3.1 million and $2.2 million, respectively. During the years ended December 31, 2012, 2011 and 2010, share-based payment arrangements paid in stock generated tax benefits of $15.1 million, $8.1 million and $6.0 million, respectively. As a result of the Company's net operating loss position, excess tax benefits of $8.1 million in 2012, $6.6 million in 2011 and $5.0 million in 2010 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 Program) under the 1999 Long-Term Incentive Plan. The 2008 Program was established to provide additional 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 Program 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 Program expense was classified as selling, general and administrative expense in the Statements of Consolidated Income.

The peer companies for the 2008 Program were as follows:

Atlas Energy Resources, LLC	MarkWest Energy Partners, L.P.	Sempra Energy
Cabot Oil & Gas Corp.	MDU Resources Group, Inc.	Southern Union Company
Chesapeake Energy Corp.	National Fuel Gas Company	Southwestern Energy Company
CNX Gas Corp.	ONEOK, Inc.	Spectra Energy Corp
El Paso Corp.	Penn Virginia Corp.	TransCanada Corp.
Enbridge Inc.	Questar Corp.	The Williams Companies, Inc.
Energen Corp.	Range Resources Corp.	

In 2009, the Compensation Committee of the Board of Directors adopted the 2010 Executive Performance Incentive Program (2010 Program) and the 2010 July Executive Performance Incentive Program (the 2010 July Program, and together with the 2010 Program, the 2010 Programs) under the 2009 Long-Term Incentive Plan. The 2010 Programs was established to provide additional 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 154,260 units were outstanding at the beginning of 2012. The vesting of the units under the 2010 Program 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 Program) through December 31, 2012 and the level of production sales revenues over the period January 1, 2010 (July 1, 2010 for the 2010 July Program) 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 3-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.

The peer companies for the 2010 Program (the 2010 Peer Group) were as follows:

Cabot Oil & Gas Corp.	MarkWest Energy Partners, L.P.	REX Energy Corp.
Chesapeake Energy Corp.	MDU Resources Group, Inc.	Sempra Energy
CNX Gas Corp.	National Fuel Gas Company	Southern Union Company
El Paso Corp.	ONEOK, Inc.	Southwestern Energy Company
Enbridge Inc.	Penn Virginia Corp.	Spectra Energy Corp
Energen Corp.	Petroleum Development Corp.	TransCanada Corp.
EOG Resources, Inc.	Questar Corp.	The Williams Companies, Inc.
EXCO Resources, Inc.	Range Resources Corp.	XTO Energy, Inc.

The peer companies for the 2010 July Program were the same as the 2010 Peer Group except for the exclusion of CNX Gas Corp., Questar Corp. and XTO Energy, Inc.

In 2012, the Compensation Committee of the Board of Directors adopted the 2012 Executive Performance Incentive Plan (2012 Program) under the 2009 Long-Term Incentive Plan. The 2012 Program was established to provide additional 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 377,250 units were granted in 2012 and no additional units may be granted. Adjusting for 25,770 forfeitures, there were 351,480 outstanding units as of December 31, 2012. The vesting of the units under the 2012 Program will occur upon payment after the end of the performance period on December 31, 2014. The payout factor will vary between zero and 300% of the number of units granted 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 3-year risk-free rate of 0.36%. As the program includes a performance condition that affects the number of shares that will ultimately vest (cumulative 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 probable outcome grant date fair value. As of December 31, 2012, the compensation expense was recorded using a grant date fair value of $108.85, which was the specific grant date fair value computed for the outcome which management estimated to be most probable. As of December 31, 2012, there was $25.5 million of total unrecognized compensation expense related to the 2012 Program which is expected to be recognized over the next two years.

The peer companies for the 2012 Program 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.	

2007 Supply Long-Term Incentive Program

Effective in 2007, the Compensation Committee of the Board of Directors established the 2007 Supply Long-Term Incentive Program (2007 Supply Program) to provide a long-term incentive compensation opportunity to key employees in the EQT Production and EQT Midstream segments. Awards granted were earned by achieving pre-determined total sales and efficiency targets and by satisfying certain applicable employment requirements. The awards paid out at three times the initial award based upon achievement of the predetermined performance levels. The vesting of the awards under the 2007 Supply Program occurred on December 31, 2010, after the ordinary close of the performance period. The vesting resulted in approximately 0.8 million awards (300% of the award) with a value of approximately $36 million being distributed in cash during the first quarter of 2011. The Company accounted for these awards as liability awards and as such recorded compensation expense for the fair value of the awards at the end of each reporting period.

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 additional 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 awards under the 2010 SIA occurred on December 31, 2012. The payout opportunity with respect to the performance awards was contingent upon adjusted 2010 earnings before interest, taxes, depreciation and amortization 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. Adjusting for the performance multiplier, 295,635 awards were outstanding as of the beginning of 2012 and, after accruing dividends, 294,925 awards, valued at $12.6 million based on the grant date fair value, vested as of December 31, 2012. The performance awards were 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 VDA) under the 2009 Long-Term Incentive Plan. The 2011 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 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 payment was contingent upon adjusted 2011 earnings before interest, taxes, depreciation and amortization 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. Adjusting for the performance multiplier, 523,347 awards were outstanding as of the beginning of 2012. 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 were, in substance, multiple awards. The total liability recorded for the 2011 VDA was $24.1 million as of December 31, 2011. As the second tranche of the awards was paid out on December 31, 2012, there was no liability recorded as of December 31, 2012.

Effective in 2012, the Compensation Committee of the Board of Directors adopted the 2012 Value Driver Award program (2012 VDA) under the 2009 Long-Term Incentive Plan. The 2012 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 VDA, 50% of the units confirmed vest 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 payment was contingent upon adjusted 2012 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, 2012 through December 31, 2012. As of December 31, 2012, 409,357 awards including accrued dividends were outstanding under the 2012 VDA. The first tranche of the confirmed awards vested and were distributed in Company stock in January 2013. The remainder of the confirmed awards is expected to vest and be paid in Company stock in the first quarter of 2014. The Company accounts for these awards as equity awards using the $54.79 grant date fair value which was equal to the Company's 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 were, in substance, multiple awards. The total compensation cost capitalized was $5.0 million in 2012. As of December 31, 2012, there was $5.7 million of total unrecognized compensation expense related to the 2012 VDA which is expected to be fully recognized by December 31, 2013.

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 will range from zero to 300% the initial award based on the achievement of predetermined specified performance measures. Payment of the awards is expected to be distributed in Company stock after the end of the performance period, December 31, 2013. The Company accounts for these awards as equity awards using the $48.06 grant date fair value which was equal to the Company's stock price on the grant date. 244,780 awards were outstanding as of the beginning of 2012, with 228,640 outstanding as of December 31, 2012. The total compensation cost capitalized was $2.5 million and $1.9 million in 2012 and 2011, respectively. As of December 31, 2012, there was $8.2 million of total unrecognized compensation expense related to the 2011 VEP which is expected to be fully recognized by December 31, 2013.

Restricted Stock Awards

The Company granted 103,730, 65,390 and 85,720 restricted stock awards during the years ended December 31, 2012, 2011 and 2010, 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 stock, was approximately $54, $52 and $43 for the years ended December 31, 2012, 2011 and 2010, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2012, 2011 and 2010 was $1.6 million, $5.1 million and $2.9 million, respectively.

As of December 31, 2012, there was $5.3 million of total unrecognized compensation cost related to nonvested restricted stock awards, which is expected to be recognized over a remaining weighted average vesting term of approximately 18 months.

A summary of restricted stock activity as of December 31, 2012, and changes during the year then ended, is presented below:

Restricted Stock	Non-Vested Shares	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2012	180,950	$ 43.10	$ 7,798,194
Granted	103,730	$ 53.50	5,550,057
Vested	(46,452)	$ 34.31	(1,593,612)
Forfeited	(34,110)	$ 46.25	(1,577,709)
Outstanding at December 31, 2012	204,118	$ 49.86	$ 10,176,930

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, 2012, 2011 and 2010. 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 historical dividend yield of the Company's stock. Expected volatilities are based on historical volatility of the Company's 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,		
	2012	2011	2010
Risk-free interest rate	0.89%	2.02%	1.60% - 2.50%
Dividend yield	1.64%	2.19%	2.10% - 2.34%
Volatility factor	0.31	0.29	0.28
Expected term	5 years	5 years	5 years

The Company granted 278,300, 229,100 and 409,100 stock options during the years ended December 31, 2012, 2011 and 2010, respectively. The weighted average grant date fair value of the options was $13.19, $10.06 and $9.31 for the years ended December 31, 2012, 2011 and 2010, respectively. The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010 was $11.8 million, $18.3 million and $7.5 million, respectively.

As of December 31, 2012, there was $1.8 million of total unrecognized compensation cost related to outstanding nonvested stock options which will be recognized by December 31, 2013.

A summary of option activity as of December 31, 2012, 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, 2012	1,946,787	$ 40.51		
Granted	278,300	$ 54.79		
Exercised	(325,035)	$ 20.70		
Forfeited	(46,577)	$ 45.93		
Outstanding at December 31, 2012	1,853,475	$ 45.99	4.0 years	$ 22,291,945
Exercisable at December 31, 2012	1,460,625	$ 44.41	2.9 years	$ 19,883,267

Non-employee Directors' Share-Based Awards

The Company has historically granted to non-employee directors share-based awards which vest upon award. The value of the share-based awards will be paid in cash or Company stock on the earlier of the director's death or retirement from the Company's Board of Directors. 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. A total of 153,861 non-employee director share-based awards were outstanding as of December 31, 2012. A total of 28,140, 22,140 and 28,348 share-based awards were granted to non-employee directors during the years ended December 31, 2012, 2011 and 2010, respectively. The weighted average fair value of these grants, based on the grant date fair value of the Company's stock, was $53.47, $44.84 and $38.74 for the years ended December 31, 2012, 2011 and 2010, respectively.

EQM Long-Term Incentive Plan Awards

At the closing of the Partnership's IPO on July 2, 2012, the Company and the general partner of the Partnership granted certain key EQT employees performance awards 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 Company's common units from the date of grant is at least 10%. If the unitholder return measure 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 these awards as equity awards using the $20.02 grant date fair value 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 volatility 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%. As of December 31, 2012, there were 146,490 performance awards outstanding. As of December 31, 2012, there was $2.5 million of total unrecognized compensation cost related to nonvested performance awards; which is expected to be recognized over a period of 3 years.

Additionally, the general partner of the Partnership granted 4,780 share-based phantom units to its independent directors, which awards vested upon grant. The value of the phantom units will be paid in Partnership common units 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.

2013 Value Driver Award Program and 2013 Executive Performance Incentive Plan

Effective 2013, the Compensation Committee of the Board of Directors adopted the 2013 Value Driver Award program (2013 VDA) and the 2013 Executive Performance Incentive Program (2013 EPIP) under the 2009 Long-Term Incentive Plan. The 2013 VDA and 2013 EPIP were established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company.

A total of 270,030 units were granted under the 2013 VDA. Fifty percent of the units confirmed under the 2013 VDA will vest upon the payment date following the first anniversary of the grant date; the remaining 50% of the confirmed units under the 2013 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 units granted contingent upon adjusted 2013 earnings before interest, taxes, depreciation and amortization 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. If earned, the 2013 VDA units are expected to be paid in Company stock. The Company has not recorded any obligation or expense related to the 2013 VDA as of December 31, 2012.

A total of 307,250 units were granted under the 2013 EPIP. The vesting of the units under the 2013 EPIP will occur upon payment after the end of the 3-year performance period. The payout will vary between zero and 300% of the number of units granted 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. If earned, the 2013 Program units are expected to be distributed in Company stock. The Company has not recorded any obligation or expense related to the 2013 EPIP as of December 31, 2012.

2013 Stock Options

Effective January 1, 2013, the Compensation Committee of the Board of Directors granted non-qualified stock options to key employees of the Company. The 2013 options are ten-year options, with an exercise price of $58.98 and a vesting schedule as follows: 50% on January 1, 2014 and 50% on January 1, 2015, contingent upon continued employment with the Company on such dates. The Company has not recorded any obligation or expense related to 2013 stock options as of December 31, 2012.

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 limited amounts of crude oil to marketers, utility and industrial customers located mainly in the Appalachian area and a gas processor in Kentucky. No single customer accounted for more than 10% of revenues in 2012, 2011 or 2010.

Approximately 75% and 66% of the Company's accounts receivable balance as of December 31, 2012 and 2011, respectively, represent amounts due from marketers. The Company manages the credit risk of sales to marketers by limiting its dealings to those marketers who 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, 2012, 2011 or 2010.

The transmission and storage operations of EQT Midstream include FERC-regulated interstate pipeline transportation and storage service for the Distribution segment, as well as other utility and end-user customers located in the northeastern United States. EQT Midstream also provides commodity procurement and delivery, physical natural gas management operations and control and customer support services to energy consumers including large industrial, utility, commercial and institutional consumers and certain marketers primarily in the Appalachian and mid-Atlantic regions.

Distribution's operating revenues and related accounts receivable are generated primarily from state-regulated distribution natural gas sales and transportation to approximately 277,400 residential, commercial and industrial customers located in southwestern Pennsylvania, northern West Virginia and eastern Kentucky. Distribution continues to monitor and analyze various customer-related metrics and their impact on accounts receivable. The Company employs a firm collections strategy which is comprised of various collection tactics including outreach to low income customers to provide information regarding energy assistance programs and, if necessary, termination of service. The outreach to low income customers includes enrolling customers into the customer assistance program which is an affordable payment plan for low income customers based on a percentage of total household income. This program is managed by the Company and recovered through rates charged to other residential customers.

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 Commodity Futures Trading Commission 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, collar and option 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 exposure to financial counterparties. This includes monitoring market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits. To manage the level of credit risk, the Company deals 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, 2012, the Company was not in default under any derivative contracts and has no knowledge of default by any counterparty to derivative contracts. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

The Company and its subsidiaries had 1,873 employees at the end of 2012. As of December 31, 2012, approximately 10% of the Company's workforce was subject to collective bargaining agreements. The collective bargaining agreement which covers approximately 8% of the Company's workforce will expire on July 8, 2015. The collective bargaining agreement which covers approximately 2% of the Company's workforce was extended in the fourth quarter of 2012 to January 22, 2016.

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, 2012 totaled $2,032.9 million (2013 - $239.4 million, 2014 - $177.8 million, 2015 - $152.6 million, 2016 - $145.4 million, 2017 - $141.3 million and thereafter - $1,176.4 million). The Company has entered into agreements to release some of its capacity to various third parties. Included in the amounts above is capacity released to third parties under long-term agreements as of December 31, 2012 totaling $129.8 million (2013 - $75.0 million, 2014 - $27.4 million, zero in 2015, 2016 and 2017 and $27.4 million thereafter).

The Company has agreements with drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $65.4 million as of December 31, 2012. Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $47.3 million in 2012, $76.9 million in 2011 and $97.4 million in 2010. Future lease payments under non-cancelable operating leases as of December 31, 2012 totaled $165.4 million (2013 - $39.7 million, 2014 - $29.4 million, 2015 - $19.1 million, 2016 - $14.2 million, 2017 - $8.6 million and thereafter - $54.4 million). The Company has subleased three floors of its previous corporate headquarters building. The Company will receive future lease payments under the non-cancelable subleases totaling approximately $28.3 million as of December 31, 2012 (2013 - $2.2 million, 2014 - $2.2 million, 2015 - $2.2 million, 2016 - $2.2 million, 2017 - $2.2 million and thereafter - $17.3 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 $2.2 million is included in other credits in the Consolidated Balance Sheets as of December 31, 2012.

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 are approximately $192 million as of December 31, 2012, extending at a decreasing amount for approximately 15 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 FASB 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.

20. Interim Financial Information (Unaudited)

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

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(Thousands, except per share amounts)			
2012 (a)				
Operating revenues	$ 449,960	$ 337,804	$ 364,057	$ 489,787
Operating income	152,186	81,404	85,948	150,990
Net income attributable to EQT Corporation	72,035	31,446	31,873	48,041
Earnings per share of common stock:				
Net income				
Basic	$ 0.48	$ 0.21	$ 0.21	$ 0.32
Diluted	$ 0.48	$ 0.21	$ 0.21	$ 0.32
2011 (a)				
Operating revenues	$ 472,695	$ 367,791	$ 362,644	$ 436,804
Operating income	220,412	153,170	314,984	172,753
Net income	122,255	87,754	178,914	90,846
Earnings per share of common stock:				
Net income				
Basic	$ 0.82	$ 0.59	$ 1.20	$ 0.61
Diluted	$ 0.82	$ 0.58	$ 1.19	$ 0.60

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

Differences between operating revenues in the above table and those previously reported in the Company's 2011 Form 10-Qs is the result of the adjustment to operating revenues and purchased gas costs to reflect third-party transportation charges as a component of purchased gas costs rather than as a deduction from operating revenues. See discussion in Note 3.

Differences between operating income in the above table and those previously reported in the Company's Form 10-Qs for the three months ended March 31, 2011 and September 30, 2011 reflect the reclassification of the gains on the dispositions of Langley and Big Sandy described in Note 6 into operating income from other income.

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 and oil production activities (a):

	For the Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
At December 31:			
Capitalized costs	$ 6,750,343	$ 5,772,083	$ 4,655,217
Accumulated depreciation and depletion	1,572,775	1,177,526	967,473
Net capitalized costs	$ 5,177,568	$ 4,594,557	$ 3,687,744
Costs incurred for the years ended December 31:			
Property acquisition:			
Proved properties (b)	$ 16,965	$ 108,717	$ 15,359
Unproved properties	117,654	41,085	342,372
Exploration (c)	4,827	2,344	5,105
Development	850,854	928,294	881,331

(a) Amounts exclude capital expenditures for facilities and information technology.
(b) Amount includes $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 and oil production.

	For the Years Ended December 31,		
	2012	2011	2010
		(Thousands)	
Revenues:			
Affiliated	$ 3,433	$ 6,225	$ 7,371
Nonaffiliated	790,340	785,060	530,286
Production costs	96,155	80,911	67,414
Exploration costs	10,370	4,932	5,368
Depreciation, depletion and accretion	409,628	257,144	183,699
Income tax expense	109,660	174,835	106,847
Results of operations from producing activities (excluding corporate overhead)	$ 167,960	$ 273,463	$ 174,329

Reserve Information

The information presented below represents estimates of proved natural gas 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 24 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 between prior year reserves and current year reserves is reviewed by senior management; and the estimates of proved natural gas and oil reserves are audited by the independent consulting firm of Ryder Scott Company, L.P. (Ryder Scott), who 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 and liquid hydrocarbon proved reserves attributable to the Company's interests as of December 31, 2012. 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,		
	2012	**2011**	**2010**
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	5,347,386	5,205,692	4,056,059
Revision of previous estimates	(755,788)	(393,129)	(606,308)
Purchase of natural gas in place	–	39,436	2,536
Sale of natural gas in place	(694)	(1,223)	(1,679)
Extensions, discoveries and other additions	1,654,228	694,180	1,893,387
Production	(259,374)	(197,570)	(138,303)
End of year	5,985,758	5,347,386	5,205,692
Proved developed reserves:			
Beginning of year	2,948,546	2,520,569	2,061,353
End of year	2,779,187	2,948,546	2,520,569

	Years Ended December 31,		
	2012	**2011**	**2010**
	(Thousands of Bbls)		
Oil (a)			
Proved developed and undeveloped reserves:			
Beginning of year	2,931	2,307	2,016
Revision of previous estimates	265	781	411
Purchase of oil in place	–	51	–
Sale of oil in place	–	–	–
Extensions, discoveries and other additions	268	–	–
Production	(265)	(208)	(120)
End of year	3,199	2,931	2,307
Proved developed reserves:			
Beginning of year	2,931	2,307	2,016
End of year	3,199	2,931	2,307

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

As discussed in Note 7, 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 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 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 fields and additional proved locations in the Company's Wetzel and Doddridge County, West Virginia development areas.

Proved developed non-producing reserves decreased 401 Bcfe during 2012 as compared to 2011. During 2012, the Company incurred a higher percentage of its costs on the well completion phase compared to the drilling phase because of longer laterals, reduced cluster spacing and multi-well pads. As a result, the Company changed its methodology for classifying wells as proved developed non-producing reserves until only after the fracturing process has been completed.

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.

During 2010, the Company recorded downward revisions of 603.8 Bcfe to the December 31, 2009 estimates of its reserves primarily due to removing proved undeveloped reserves in the Huron play in order to focus more capital and resources in the Marcellus play over the five-year time horizon included in the proved undeveloped reserves development plan, partially offset by increased prices. The Company's 2010 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 1,893.4 Bcfe exceeded the 2010 production of 139.0 Bcfe.

As of December 31, 2012, the Company did not have any reserves that have been classified as proved undeveloped reserves for more than five years.

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:

	2012	2011	2010
		(Thousands)	
Future cash inflows (a)	$ 15,250,019	$ 22,145,953	$ 20,037,125
Future production costs	(3,070,957)	(3,435,200)	(3,313,378)
Future development costs	(3,082,053)	(2,600,982)	(2,497,312)
Future income tax expenses	(3,324,472)	(6,075,539)	(8,756,630)
Future net cash flow	5,772,537	10,034,232	5,469,805
10% annual discount for estimated timing of cash flows	(3,617,378)	(6,101,408)	(2,411,593)
Standardized measure of discounted future net cash flows	$ 2,155,159	$ 3,932,824	$ 3,058,212

(a) The majority of the Company's production is sold through liquid trading points on interstate pipelines. 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.

For 2010, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2010 of $76.68 per Bbl of oil (first day of each month closing price for WTI less Appalachian Basin adjustment), $4.502 per Dth for Columbia Gas Transmission Corp., $4.563 per Dth for Dominion Transmission, Inc., $4.407 per Dth for the East Tennessee Natural Gas Pipeline and $4.422 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company.

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, 2012 discounted future net cash flows before income taxes of the Company's proved reserves of approximately $1.7 billion and $10.6 million, respectively.

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

	2012	2011	2010
		(Thousands)	
Sales and transfers of natural gas and oil produced – net	$ (697,618)	$ (710,373)	$ (470,243)
Net changes in prices, production and development costs	(3,530,086)	52,057	807,971
Extensions, discoveries and improved recovery, less related costs	917,986	806,597	1,739,308
Development costs incurred	548,852	498,175	310,557
Purchase of minerals in place – net	−	46,178	2,330
Sale of minerals in place – net	(807)	(1,124)	(532)
Revisions of previous quantity estimates	(876,336)	(356,830)	(191,336)
Accretion of discount	622,072	478,165	128,741
Net change in income taxes	1,127,272	(560,360)	(1,239,035)
Timing and other (a)	111,000	622,127	1,171,697
Net (decrease) increase	(1,777,665)	874,612	2,259,458
Beginning of year	3,932,824	3,058,212	798,754
End of year	$ 2,155,159	$ 3,932,824	$3,058,212

(a) The change in the Company's future drilling plans to include a higher percentage of wells drilled from the Marcellus play resulted in an increase during the years ended December 31, 2011 and 2010 in discounted future net cash flows due to the higher initial production rates and lower development costs per Mcfe from these wells.

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 2012 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, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2012.

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.

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 17, 2013, which will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2012:

- 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 Three-Year Term Expiring in 2016," "Directors Whose Terms Expire in 2014," "Directors Whose Terms Expire in 2015" 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 "Stock 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 – Meetings of the Board of Directors and Committee Membership – 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 – Meetings of the Board of Directors and Committee Membership – 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 21, 2013)," 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 17, 2013, which will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2012:

- 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," "Executive Compensation" and "Directors' 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

Committee Interlocks and Insider Participation" and "Executive Compensation – 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

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 to the sections captioned "Stock Ownership – Stock Ownership of Significant Shareholders" and "Stock Ownership – Stock Ownership of Directors and Executive Officers" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 17, 2013, which will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2012.

EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2012 with respect to shares of the Company's common stock that may be issued under the Company's existing equity compensation plans, including the 2009 Long-Term Incentive Plan (2009 LTIP), the 1999 Long-Term Incentive Plan (1999 LTIP), the 1999 Non-Employee Directors' Stock Incentive Plan (1999 NEDSIP), the Directors' Deferred Compensation Plan, the 2005 Directors' Deferred Compensation Plan and the 2008 Employee Stock Purchase Plan (2008 ESPP).

Plan Category	Number Of Securities To Be Issued Upon Exercise Of Outstanding Options, Warrants and Rights (A)	Weighted Average Exercise Price Of Outstanding Options, Warrants and Rights (B)	Number Of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected In Column A) (C)
Equity Compensation Plans Approved by Shareholders (1)	4,355,346	$ 45.99 (3)	3,180,405 (4)
Equity Compensation Plans Not Approved by Shareholders (2)	22,608 (5)	N/A	122,753
Total	4,377,954 (5)	$ 45.99 (3)	3,303,158 (4)

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(1) Includes the 2009 LTIP, including performance share awards and dividend reinvestments thereon under the 2012 EPIP, the 2012 VDA and the 2011 VEP and deferred stock units and dividend reinvestments thereon; the 1999 LTIP; the 1999 NEDSIP, including the deferred stock units and dividend reinvestments thereon; and the 2008 ESPP.

(2) Includes shares issuable under the Directors' Deferred Compensation Plan and the 2005 Directors' Deferred Compensation Plan (collectively, the Director Deferral Plans). The Director Deferral Plans are described below.

(3) The weighted-average exercise price is calculated solely based upon outstanding stock options and excludes deferred stock units under the 1999 NEDSIP and the 2009 LTIP and performance awards under the 2012 EPIP, the 2012 VDA and the 2011 VEP.

[4] 797,021 shares remain available for issuance under the 2008 ESPP and 3,561 shares were subject to purchase at December 31, 2012.

[5] Shares issuable under the Director Deferral Plans consist of 22,608 shares representing fees deferred by directors and including dividends thereon.

2005 Directors' Deferred Compensation Plan

The 2005 Directors' Deferred Compensation Plan was adopted by the Management Development and Compensation Committee of the Board of Directors, effective January 1, 2005. The plan has been amended to allow the plan to continue into 2006 and thereafter and to comply with the documentation requirements of Section 409A of the Internal Revenue Code. Neither the original adoption of the plan nor its amendments required approval by shareholders. The plan allows non-employee directors to defer all or a portion of their directors' fees and retainers. Amounts deferred are payable upon retirement from the Board unless an early payment is authorized after the director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers, the deferred stock units granted to directors on or after January 1, 2005 under the 1999 Non-Employee Directors' Stock Incentive Plan and the 2009 Long-Term Incentive Plan are administered under this plan.

Directors' Deferred Compensation Plan

The Directors' Deferred Compensation Plan was suspended as of December 31, 2004. The Directors' Deferred Compensation Plan continues to operate for the sole purpose of administering vested amounts deferred under the plan on or prior to December 31, 2004. Deferred amounts are generally payable upon retirement from the Board, but may be payable earlier if an early payment is authorized after a director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers and a one-time grant of deferred shares in 1999, the deferred stock units granted to directors and vested prior to January 1, 2005 under the 1999 Non-Employee Directors' Stock Incentive Plan are administered under this plan.

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 – Director Independence," "Corporate Governance and Board Matters – Review, Approval or Ratification of Transactions with Related Persons" and "Corporate Governance and Board Matters – Transactions with Related Persons" in the Company's definitive proxy statement relating to the annual meeting of shareholders to be held on April 17, 2013, which will be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2012.

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. 2 – 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 17, 2013, which will be filed with the Commission within 120 days after the close of the Company's fiscal year ended December 31, 2012.

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 120 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:

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.

EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2012

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	Deductions (a)	Balance at End of Period
			(Thousands)		
Allowance for doubtful accounts:					
2012………………………..	$ 16,371	$ (1,235)	$ −	$ 2,550	$ 12,586
2011………………………..	$ 18,335	$ 1,581	$ −	$ 3,545	$ 16,371
2010………………………	$ 16,792	$ 5,134	$ −	$ 3,591	$ 18,335

Note:

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
2.01	Master Purchase Agreement dated as of December 19, 2012 among the Company, Distribution Holdco, LLC and PNG Companies LLC	Filed as Exhibit 2.1 to Form 8-K filed on December 20, 2012
2.02	Asset Exchange Agreement dated as of December 19, 2012 between the Company and PNG Companies LLC	Filed as Exhibit 2.2 to Form 8-K filed on December 20, 2012
3.01	Restated Articles of Incorporation of EQT Corporation (amended through May 10, 2011)	Filed as Exhibit 3.1 to Form 8-K filed on May 10, 2011
3.02	Amended and Restated By-Laws of EQT Corporation (amended through May 10, 2011)	Filed as Exhibit 3.2 to Form 8-K filed on May 10, 2011
4.01(a)	Indenture dated as of April 1, 1983 between the Company and Pittsburgh National Bank, as Trustee	Filed as Exhibit 4.01(a) to Form 10-K for the year ended December 31, 2007
4.01(b)	Instrument appointing Bankers Trust Company as successor trustee to Pittsburgh National Bank	Filed as Exhibit 4.01(b) to Form 10-K for the year ended December 31, 1998
4.01(c)	1991 Supplemental Indenture dated as of March 15, 1991 between the Company and Bankers Trust Company, as Trustee, eliminating limitations on liens and additional funded debt	Filed as Exhibit 4.01(f) to Form 10-K for the year ended December 31, 1996
4.01(d)	Resolution adopted August 19, 1991 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 27, establishing the terms and provisions of the Series A Medium-Term Notes	Filed as Exhibit 4.01(g) to Form 10-K for the year ended December 31, 1996
4.01(e)	Resolutions adopted July 6, 1992 and February 19, 1993 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 8, establishing the terms and provisions of the Series B Medium-Term Notes	Filed as Exhibit 4.01(h) to Form 10-K for the year ended December 31, 1997
4.01(f)	Resolution adopted July 14, 1994 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 and 2, establishing the terms and provisions of the Series C Medium-Term Notes	Filed as Exhibit 4.01 to Form 10-K for the year ended December 31, 1995
4.01(g)	Second Supplemental Indenture dated as of June 30, 2008 between the Company and Deutsche Bank Trust Company Americas, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Filed as Exhibit 4.01(g) to Form 8-K filed on July 1, 2008

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
4.02(a)	Indenture dated as of July 1, 1996 between the Company and with The Bank of New York, as successor to Bank of Montreal Trust Company, as Trustee dated as of July 1, 1996	Filed as Exhibit 4.01(a) to Form S-4 Registration Statement (#333-103178) filed on February 13, 2003
4.02(b)	Resolution adopted January 18 and July 18, 1996 by the Board of Directors of the Company and Resolutions adopted July 18, 1996 by the Executive Committee of the Board of Directors of the Company, establishing the terms and provisions of the 7.75% Debentures issued July 29, 1996	Filed as Exhibit 4.01(j) to Form 10-K for the year ended December 31, 1996
4.02(c)	Officer's Declaration dated as of February 20, 2003 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of up to $200,000,000	Filed as Exhibit 4.01(c) to Form S-4 Registration Statement (#333-104392) filed on April 8, 2003
4.02(d)	Officer's Declaration dated as of November 7, 2002 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of up to $200,000,000	Filed as Exhibit 4.01(c) to Form S-4/A Registration Statement (#333-103178) filed on March 12, 2003
4.02(e)	Officer's Declaration dated as of September 27, 2005 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of $150,000,000	Filed as Exhibit 4.01(b) to Form S-4 Registration Statement (#333-104392) filed on October 28, 2005
4.02(f)	Supplemental Indenture dated as of June 30, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Filed as Exhibit 4.02(f) to Form 8-K filed on July 1, 2008
4.03(a)	Indenture dated as of March 18, 2008 between the Company and The Bank of New York, as Trustee	Filed as Exhibit 4.1 to Form 8-K filed on March 18, 2008
4.03(b)	First Supplemental Indenture (including the form of senior note) dated as of March 18, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which the 6.5% Senior Notes due 2018 were issued	Filed as Exhibit 4.2 to Form 8-K filed on March 18, 2008
4.03(c)	Second Supplemental Indenture dated as of June 30, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture	Filed as Exhibit 4.03(c) to Form 8-K filed on July 1, 2008

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
4.03(d)	Third Supplemental Indenture dated as of May 15, 2009 between the Company and The Bank of New York, as Trustee, pursuant to which the 8.125% Senior Notes due 2019 were issued	Filed as Exhibit 4.1 to Form 8-K filed on May 15, 2009
4.03(e)	Fourth Supplemental Indenture dated as of November 7, 2011 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 4.875% Senior Notes due 2021 were issued	Filed as Exhibit 4.2 to Form 8-K filed on November 7, 2011
* 10.01(a)	1999 Long-Term Incentive Plan (as amended and restated July 11, 2012)	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2012
* 10.01(b)	Form of Participant Award Agreement (Stock Option) under 1999 Long-Term Incentive Plan (pre-2007)	Filed as Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2004
* 10.01(c)	Form of Participant Award Agreement (Stock Option) under 1999 Long-Term Incentive Plan (2007 and later)	Filed as Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2008
* 10.01(d)	2007 Supply Long-Term Incentive Program (as amended and restated March 5, 2009)	Filed as Exhibit 10.4 to Form 10-Q for the quarter ended March 31, 2009
* 10.01(e)	Form of Participant Award Agreement under 2007 Supply Long-Term Incentive Program	Filed as Exhibit 10.01(i) to Form 10-K for the year ended December 31, 2008
* 10.01(f)	2008 Executive Performance Incentive Program	Filed as Exhibit 10.6 to Form 10-Q for the quarter ended March 31, 2009
* 10.01(g)	Form of Participant Award Agreement under 2008 Executive Performance Incentive Program	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2008
* 10.02(a)	2009 Long-Term Incentive Plan (as amended and restated July 11, 2012)	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2012
* 10.02(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (pre-2013)	Filed herewith as Exhibit 10.02(b)
* 10.02(c)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (pre-2012)	Filed as Exhibit 10.01(q) to Form 10-K for the year ended December 31, 2010
* 10.02(d)	2010 Executive Performance Incentive Program	Filed as Exhibit 10.01(r) to Form 10-K for the year ended December 31, 2009
* 10.02(e)	Form of Participant Award Agreement under 2010 Executive Performance Incentive Program	Filed as Exhibit 10.01(s) to Form 10-K for the year ended December 31, 2009
* 10.02(f)	Form of 2010 Stock Incentive Award Agreement	Filed as Exhibit 10.01(t) to Form 10-K for the year ended December 31, 2009

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.02(g)	Form of Amendment to 2010 Stock Incentive Award Agreement	Filed as Exhibit 10.01(u) to Form 10-K for the year ended December 31, 2010
* 10.02(h)	2010 July Executive Performance Incentive Program	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010
* 10.02(i)	Form of 2011 Value Driver Performance Award Agreement	Filed as Exhibit 10.01(w) to Form 10-K for the year ended December 31, 2010
* 10.02(j)	Form of Amendment to 2011 Value Driver Performance Award Agreement	Filed as Exhibit 10.02(k) to Form 10-K for the year ended December 31, 2011
* 10.02(k)	2011 Volume and Efficiency Program	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2011
* 10.02(l)	Form of Participant Award Agreement under 2011 Volume and Efficiency Program	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2011
* 10.02(m)	Form of Amendment to Stock Option Award Agreements	Filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2011
* 10.02(n)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2012 grants)	Filed as Exhibit 10.02(n) to Form 10-K for the year ended December 31, 2011
10.02(o)	Form of 2012 Value Driver Performance Award Agreement	Filed as Exhibit 10.02(p) to Form 10-K for the year ended December 31, 2011
* 10.02(p)	2012 Executive Performance Incentive Program	Filed as Exhibit 10.02(q) to Form 10-K for the year ended December 31, 2011
* 10.02(q)	Form of Participant Award Agreement under 2012 Executive Performance Incentive Program	Filed as Exhibit 10.02(r) to Form 10-K for the year ended December 31, 2011
* 10.02(r)	Form of EQM TSR Performance Award Agreement under 2009 Long-Term Incentive Plan and EQT Midstream Services, LLC 2012 Long-Term Incentive Plan	Filed herewith as Exhibit 10.02(r)
* 10.02(s)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (2013 grants)	Filed herewith as Exhibit 10.02(s)
* 10.02(t)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2013 grants)	Filed herewith as Exhibit 10.02(t)
* 10.02(u)	2013 Executive Performance Incentive Program	Filed herewith as Exhibit 10.02(u)

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.02(v)	Form of Participant Award Agreement under 2013 Executive Performance Incentive Program	Filed herewith as Exhibit 10.02(v)
10.02(w)	Form of 2013 Value Driver Performance Award Agreement	Filed herewith as Exhibit 10.02(w)
* 10.03	EQT Midstream Services, LLC 2012 Long-Term Incentive Plan	Filed herewith as Exhibit 10.03
* 10.04(a)	1999 Non-Employee Directors' Stock Incentive Plan (as amended and restated December 3, 2008)	Filed as Exhibit 10.02(a) to Form 10-K for the year ended December 31, 2008
* 10.04(b)	Form of Participant Award Agreement (Stock Option) under 1999 Non-Employee Directors' Stock Incentive Plan	Filed as Exhibit 10.04(b) to Form 10-K for the year ended December 31, 2006
* 10.04(c)	Form of Participant Award Agreement (Phantom Units Award) under 1999 Non-Employee Directors' Stock Incentive Plan	Filed as Exhibit 10.04(c) to Form 10-K for the year ended December 31, 2006
* 10.05	Executive Short-Term Incentive Plan (as amended and restated December 3, 2008)	Filed as Exhibit 10.03 to Form 10-K for the year ended December 31, 2008
* 10.06	2011 Executive Short-Term Incentive Plan	Filed as Exhibit 10.2 to Form 8-K filed on May 10, 2011
* 10.07	2006 Payroll Deduction and Contribution Program (as amended and restated February 19, 2013)	Filed herewith as Exhibit 10.07
* 10.08	Directors' Deferred Compensation Plan (as amended and restated May 15, 2003)	Filed as Exhibit 10.10 to Form 10-Q for the quarter ended June 30, 2003
* 10.09	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
* 10.10(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
* 10.10(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and David L. Porges	Filed herewith as Exhibit 10.10(b)
* 10.11(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

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.11(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Philip P. Conti	Filed herewith as Exhibit 10.11(b)
* 10.12(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Randall L. Crawford	Filed as Exhibit 10.01 to Form 10-Q for the quarter ended March 31, 2012
* 10.12(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Randall L. Crawford	Filed herewith as Exhibit 10.12(b)
* 10.13(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Lewis B. Gardner	Filed as Exhibit 10.13(a) to Form 10-K for the year ended December 31, 2008
* 10.13(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Lewis B. Gardner	Filed herewith as Exhibit 10.13(b)
* 10.14(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Steven T. Schlotterbeck	Filed as Exhibit 10.16(a) to Form 10-K for the year ended December 31, 2008
* 10.14(b)	Amended and Restated Change of Control Agreement dated as of February 19, 2013 between the Company and Steven T. Schlotterbeck	Filed herewith as Exhibit 10.14(b)
* 10.15	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
10.16(a)	Revolving Credit Agreement, dated as of December 8, 2010 among the Company, PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, JPMorgan Chase Bank, N.A., Bank of America, N.A., and Wells Fargo Bank, N.A., as Co-Syndication Agents and L/C Issuers, Barclays Bank PLC, as Documentation Agent and an L/C Issuer, and other lender parties thereto	Filed as Exhibit 10.1 to Form 8-K filed on December 9, 2010
10.16(b)	Amendment No. 1 to Revolving Credit Agreement dated as of May 8, 2012 among the Company, PNC Bank National Association, as Administrative Agent, Swing Ling Lender and a lender, and other lender parties thereto	Filed as Exhibit 10.1 to Form 8-K filed on May 8, 2012

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

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
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
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.

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

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 21, 2013

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 21, 2013
/s/ PHILIP P. CONTI Philip P. Conti (Principal Financial Officer)	Senior Vice President and Chief Financial Officer	February 21, 2013
/s/ THERESA Z. BONE Theresa Z. Bone (Principal Accounting Officer)	Vice President and Corporate Controller	February 21, 2013
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 21, 2013
/s/ PHILIP G. BEHRMAN Philip G. Behrman	Director	February 21, 2013
/s/ KENNETH M. BURKE Kenneth M. Burke	Director	February 21, 2013
/s/ A. BRAY CARY JR. A. Bray Cary Jr.	Director	February 21, 2013
/s/ MARGARET K. DORMAN Margaret K. Dorman	Director	February 21, 2013
/s/ GEORGE L. MILES, JR. George L. Miles, Jr.	Director	February 21, 2013
/s/ JAMES E. ROHR James E. Rohr	Director	February 21, 2013
/s/ DAVID S. SHAPIRA David S. Shapira	Director	February 21, 2013

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/s/ STEPHEN A. THORINGTON Stephen A. Thorington	Director	February 21, 2013
/s/ LEE T. TODD, JR. Lee T. Todd, Jr.	Director	February 21, 2013

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Exhibit 31.01

CERTIFICATION

I, David L. Porges, certify that:

1. I have reviewed this Annual Report on Form 10-K of EQT Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ David L. Porges

David L. Porges
Chairman, President and Chief Executive Officer

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Exhibit 31.02

CERTIFICATION

I, Philip P. Conti, certify that:

1. I have reviewed this Annual Report on Form 10-K of EQT Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ Philip P. Conti

Philip P. Conti
Senior Vice President and Chief Financial Officer

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Exhibit 32

CERTIFICATION

In connection with the Annual Report of EQT Corporation (the “Company”) on Form 10-K for the period ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned certify pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David L. Porges — February 21, 2013
David L. Porges, Chairman, President and
Chief Executive Officer

/s/ Philip P. Conti — February 21, 2013
Philip P. Conti, Senior Vice President and
Chief Financial Officer

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