EQT Corp
Form 10-K
February 16, 2012
Table of Contents

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, 2011

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** (Address of principal executive offices)	**15222** (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, 2011: $5,389,512,917

The number of shares of common stock outstanding

as of January 31, 2012: 149,490,315

DOCUMENTS INCORPORATED BY REFERENCE

The Company s definitive proxy statement relating to the annual meeting of shareowners (to be held April 18, 2012) will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2011 and is incorporated by reference in Part III to the extent described therein.

TABLE OF CONTENTS

Table of Contents

Glossary of Commonly Used Terms, Abbreviations and Measurements

Commonly Used Terms

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

Appalachian Basin the area of the United States 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.

CAP Customer Assistance Program - a payment plan for low-income residential gas customers that sets a fixed payment for natural gas usage based on a percentage of total household income. The cost of the CAP is spread across non-CAP customers.

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.

Table of Contents

Glossary of Commonly Used Terms, Abbreviations and Measurements

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.

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 or 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.

Table of Contents

Glossary of Commonly Used Terms, Abbreviations and Measurements

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

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

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.

Abbreviations

ASC - Accounting Standards Codification

CBM Coalbed Methane

CFTC Commodity Futures Trading Commission

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

IRS Internal Revenue Service

LDC Local Distribution Company

NGV Natural Gas Vehicle

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

Table of Contents

Cautionary Statements

Disclosures in this Annual Report on Form 10-K contain certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Statements that do not relate strictly to historical or current facts are forward-looking and usually identified by the use of words such as anticipate, estimate, could, would, will, m forecasts, approximate, expect, project, intend, plan, believe and other words of similar meaning in connection with any discussion of operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this report include the matters discussed in the sections captioned 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 and the availability of capital to complete these plans and programs); production and sales volumes; gathering and transmission growth and volumes; infrastructure programs (including the Sunrise Pipeline project and the gathering expansion projects); technology (including drilling and fracturing techniques); transactions (including asset sales, joint ventures or other transactions involving the Company s assets); conversion of its automobile fleet and certain rigs to natural gas; revenue projections; reserves (including estimated reserve life, operating costs; well costs; unit costs; capital expenditures; estimates of cost to develop wells; financing requirements and availability; hedging strategy; the effects of government regulation 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. 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 statements, whether as a result of new information, future events or otherwise.

In reviewing any agreements incorporated by reference in or filed with Annual Report or this 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.

Table of Contents

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 5.4 Tcfe of proved reserves across 3.5 million acres, including approximately 530,000 acres in the Marcellus play, as of December 31, 2011. EQT Midstream provides gathering, transmission and storage services for the Company s produced gas and to independent third parties in the Appalachian Basin. Until February 1, 2011 when the company sold the Kentucky Hydrocarbon gas processing facility in Langley, Kentucky (Langley), EQT Midstream also provided processing services. Distribution, through its regulated natural gas distribution subsidiary, Equitable Gas Company, LLC (Equitable Gas), distributes and sells natural gas to residential, commercial and industrial customers in southwestern Pennsylvania, West Virginia and eastern Kentucky, operates a small gathering system in Pennsylvania and provides off-system sales activities which include the purchase and delivery of gas to customers.

EQT has 5.4 Tcfe of proved reserves across three major plays: Marcellus, Huron and CBM, all in the Appalachian Basin, including 3.4 Tcfe in the Marcellus. The Company s strategy is to maximize value by profitably developing its undeveloped Marcellus reserves. EQT believes that it is a technological leader in drilling shale in the Appalachian Basin.

EQT s proved Marcellus reserves increased by 19% in 2011, while the Company s cost structure remained at an industry leading level. As of December 31, 2011, the Company s proved reserves, including proved developed and proved undeveloped reserves, and the resource plays to which the reserves relate are as follows:

(Bcfe)	Marcellus	Huron *	CBM	Total
Proved Developed	1,015	1,775	176	2,966
Proved Undeveloped	2,399			2,399
Total Proved Reserves	3,414	1,775	176	5,365

* The Company includes the Lower Huron, Cleveland, Berea sandstone and other Devonian shales, except the Marcellus, in its Huron play. Also included in the Huron play is 713 Bcfe of reserves from non-shale formations accessed through vertical wells.

Assuming that future annual production from these reserves is consistent with 2011, the remaining reserve life of the Company s total proved reserves as calculated by dividing total proved reserves by current year produced volumes is 27 years.

The Company s natural gas wells are generally low-risk with long lives and low development and production costs. The gas produced from many of these wells has a high energy content and is within close proximity to natural gas markets. Most of the Company s Huron well production and some of its Marcellus well production is liquids-rich.

In the Marcellus, EQT applies extended lateral horizontal drilling technology to its approximate 530,000 acres and 3.4 Tcfe of proved reserves. EQT continues to be a leader in the use of new drilling and completion technology which increases lateral length drilled and reserves per foot of pay. Marcellus wells have target depths ranging from 7,000 to 8,000 feet with an average lateral spacing of 1,000 feet.

In light of lower natural gas prices and the resultant reduction in projected cash flow, the Company decided in January 2012 to suspend development in the Huron indefinitely in favor of investing in its higher return Marcellus play. A similar decision was made in December 2010, when the Company suspended the development of its CBM play in Virginia. Proved reserves from these two plays were 33% and 3%, respectively, of total proved reserves at

Table of Contents

December 31, 2011. The Company expects to continue to produce from existing wells in the Huron and CBM plays, but their contribution to the Company s total production sales volumes will gradually decline as the Company focuses all new drilling in the Marcellus. The Huron and CBM plays accounted for approximately 58% of production sales volumes in 2011 and are expected to account for approximately 40% of production sales volumes in 2012.

The Company invested approximately $938 million on well development (primarily drilling) in 2011. Production sales volumes increased 44% in 2011 over 2010. 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:	**2011**	**2010**	**2009**
Horizontal Marcellus	105	90	46
Horizontal Huron	115	236	347
Other horizontal			10
Total horizontal	220	326	403
Other	2	163	299
Total	222	489	702
Capital expenditures for well development:			
(in millions):			
Horizontal Marcellus	$ 686	$ 436	$ 118
Horizontal Huron	226	346	368
Other horizontal			66
Total horizontal	912	782	552
Other	26	106	134
Total	$ 938	$ 888	$ 686

In May 2011, the Company purchased all of the outstanding net profits interest (NPI) from the other investor (ANPI) in a trust in which EQT owned an existing interest (the ANPI transaction). This transaction resulted in an increase in oil and gas properties of $140.6 million, assumed debt and other liabilities of $92.6 million and a pre-tax gain of $10.1 million, recorded in other income, on the revaluation of the previously existing equity investment in the trust to fair value.

To support the growth of the Marcellus play, the Company is increasing its available gathering and transmission system capacity in the region. During 2011, the Company completed construction of the Callisto compressor station which added 14,205 horsepower of compression and 150 MMcfe per day of delivery capacity to the Equitrans L.P. (Equitrans, EQT s FERC-regulated transmission, storage and gathering system) gathering system for EQT production in Greene County, Pennsylvania. The Company has Marcellus gathering capacity of 440 MMcfe per day in Pennsylvania and 85 MMcfe per day in West Virginia. The Company has approximately 10,450 miles of gathering lines.

Table of Contents

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. 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.

Through EQT s gas marketing subsidiary, EQT Energy, LLC, (EQT Energy), the Company provides optimization of capacity and storage assets, NGL sales and gas sales to commercial and industrial customers within its operational footprint through 6.5 Bcf of leased storage-related assets and approximately 880,000 Dth per day of third party contractual pipeline capacity.

On February 1, 2011, EQT Midstream sold Langley and the associated NGL pipeline to MarkWest Energy Partners, L.P. (MarkWest) for $230 million subject to customary purchase price adjustments. The Company realized a pre-tax gain of $22.8 million on this sale. In conjunction with the closing of the sale of the Langley plant, EQT executed a long-term agreement with MarkWest to obtain processing services for its Kentucky Huron gas and extended its existing agreement with MarkWest for NGL transportation, fractionation and marketing services until 2022. MarkWest has commenced construction of a new cryogenic processing plant to expand the Langley cryogenic processing capacity which is expected to be on-line in 2012. In addition, MarkWest has agreed to construct a natural gas processing facility in Logansport, WV. The Logansport facility is expected to be on-line in 2012. MarkWest will then provide natural gas processing services for EQT s Marcellus production in north central West Virginia, as well as NGL transportation, fractionation and marketing services. The Sunrise Pipeline project described below will connect this facility to Equitrans and its interconnects with five major interstate pipelines.

On July 1, 2011, the Company sold the Big Sandy Pipeline (Big Sandy) to Spectra Energy Partners, LP for $390 million. Big Sandy is a natural gas pipeline regulated by the FERC which transports natural gas from the Langley natural gas processing complex to interconnects with unaffiliated pipelines leading to the mid-Atlantic and Northeast markets. In conjunction with this transaction, the Company realized a pre-tax gain of $180.1 million.

Capital expenditures for well development (primarily drilling) in 2012 are expected to be approximately $1,055 million to support the drilling of approximately 158 gross wells, including 146 gross Marcellus wells and 12 Huron wells which were either spud in January 2012 or are required to maintain lease rights. In addition, the Company plans to spend $365 million for midstream infrastructure in 2012. Sales volumes are expected to be between 250 and 255 Bcfe for an anticipated production sales volume growth of approximately 30% in 2012. The Company currently believes that the 2012 capital expenditure plan will be funded by cash flow generated from operations and cash on hand.

Strategy

EQT s strategy is to maximize shareholder value by profitably developing the Company s undeveloped Marcellus reserves by utilizing the Company s extensive gathering and transmission assets, low cost structure, close proximity to the northeastern United States markets and the high energy content of much of its produced natural gas.

The Company has used technology to increase lateral length and develop multi-well pads. Recoveries from extended laterals have been proportional to the length increase. The Company expects to continue increasing the average lateral lengths over time; however, lateral lengths will be limited by lease boundaries in the Marcellus 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 economic manner by using longer laterals and multi pad drilling rather than focusing on drilling less economic wells in order to retain acreage. The Company has produced industry leading results in its core development area in Greene County, Pennsylvania.

The Company believes the location of its midstream assets across a wide area of the Marcellus in southwestern Pennsylvania and northern West Virginia uniquely positions it for growth. In light of the growth of EQT Production and other producers in the Marcellus, EQT Midstream intends to capitalize on the growing need for

Table of Contents

gathering and transmission infrastructure in the region, especially the need for midstream header connectivity to interstate pipelines in Pennsylvania and West Virginia.

EQT plans to continue its investment in gathering and transmission capacity in the Marcellus. In 2012, the Company intends to add 445 MMcfe per day of incremental gathering capacity, 285 MMcfe per day in Pennsylvania and 160 MMcfe per day in West Virginia. Equitrans recently received approval from the FERC to proceed with construction of the Sunrise Pipeline project. The Sunrise Pipeline will provide access to liquids-rich Marcellus acreage and will consist of 41.5 miles of 24-inch diameter pipeline that parallels and interconnects with an existing segment of our transmission and storage system from Wetzel County, West Virginia to Greene County, Pennsylvania. In addition, the Sunrise Pipeline project will include connecting to a new delivery point with Texas Eastern Transmission in Green County and constructing the Jefferson compressor station, which will provide 314 BBtu, or approximately 300 MMcfe, per day of additional firm capacity to the system. The Company also intends to add another 400 MMcfe per day of additional transmission capacity in 2012. The combination of these gathering and transmission investments with existing assets will provide a platform for growth, mitigate curtailments and increase the flexibility and reliability of the Company s gathering and transmission systems.

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, PA during 2011. In conjunction with this project, the Company is promoting the use of NGV fleet vehicles, including its own. EQT plans to operate 23% of its vehicle fleet, more than 330 vehicles, on natural gas by the end of 2013. The Company also plans to convert two drilling rigs to utilize natural gas in 2012.

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 2011, 2010 or 2009.

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 outlined in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and in Notes 1 and 3 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, 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 EQT s

Langley facility 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 the Langley facility to MarkWest, the processing of the Company s produced natural gas has been performed by a third-party vendor.

Table of Contents

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:

	2011	2010	2009
Average wellhead sales price per Mcfe sold (including hedges)	$ 5.37	$ 5.62	$ 5.80
Average wellhead sales price per Mcfe sold (excluding hedges)	$ 4.85	$ 5.12	$ 4.48

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 three major interstate pipelines: Columbia Gas Transmission, East Tennessee Natural Gas Company and Dominion Transmission. 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 2011 totaled 258.2 BBtu, of which approximately 75% related to gathering for EQT Production, 16% related to third-party volumes and 9% related to volumes for other affiliates of the Company. Revenues from EQT Production and other affiliates accounted for approximately 87% of 2011 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 2012 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 2011, approximately 84% of transportation volumes and revenues were from affiliates.

Natural Gas Distribution: The Company s Distribution segment provides natural gas distribution services to approximately 276,500 customers, consisting of 257,700 residential customers and 18,800 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 Gulf Coast, local 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 and WV PSC. Equitable Gas is not permitted to profit from fluctuations in gas costs and does not purchase gas produced by EQT Production.

Because most of its customers use natural gas for heating purposes, Equitable Gas revenues are seasonal, with approximately 66% of calendar year 2011 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.

Table of Contents

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. Natural gas marketing activities compete with numerous other companies offering the same 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, the Company s 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, such as safety regulations. These regulations may impact the costs 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 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 impact the costs of or increase the time of developing new or expanded pipelines and compressor stations.

EQT Midstream has both non-regulated and regulated rate operations. The interstate natural gas transmission systems and storage operations are regulated 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 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 trading activities which are regulated by, among others, the CFTC. In July 2010, federal legislation was enacted that, among other things, established federal oversight and regulation of the OTC derivative market and entities that participate in that market. The legislation requires the SEC and CFTC to promulgate rules and regulations implementing the legislation and, as of the date of

Table of Contents

this report, most of the key implementing regulations have not been adopted. Accordingly, it is not possible at this time to predict the impact of the legislation on our hedging program.

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 Kentucky Public Service Commission.

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 allowed 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 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, drilling, operating and abandoning wells and related surface facilities. In most instances, the regulatory frameworks relate to the handling of drilling and production materials, the disposal of drilling and production wastes, the protection of water and air and the protection of people.

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 protective 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. 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.

Table of Contents

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 approximately 1,835 employees at the end of 2011. As of December 31, 2011, approximately 11% of the Company s workforce was subject to collective bargaining agreements. The collective bargaining agreement which covers approximately 9% of the Company s workforce expired on September 25, 2011. The union agreed to continue working under the terms and conditions of the expired labor agreement while the parties continue negotiations for a new agreement. The collective bargaining agreement which covers approximately 1% of the Company s workforce will expire on May 21, 2012.

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,		
	2011	**2010**	**2009**

EQT Production:			
Natural gas sales	41%	27%	26%
EQT Midstream:			
Gathering revenue	14%	13%	10%
Distribution:			
Residential natural gas sales	15%	20%	25%

Financial Information about Segments

See Note 2 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.

Table of Contents

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.

Table of Contents

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 and processing 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 in an asset position (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 natural gas liquids, 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. 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 and pollution or other environmental damage. 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

Table of Contents

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, 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 processing adjacent to and 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 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. An extended interruption of access to or service from our or third-party 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.

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.

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 2012 business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, midstream

Table of Contents

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 2012 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover economic or other circumstances may change from those contemplated by our 2012 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

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, effective January 1, 2011, the EPA began regulating greenhouse gas emission 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.

In addition, 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.

In July 2011, the EPA issued proposed rules that would 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 proposed 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 proposed regulations under NESHAP include maximum achievable control technology standards for certain equipment not currently subject to such standards. The final regulations could result in an increase to our costs or require changes that reduce our production.

Table of Contents

In addition, hydraulic fracturing is utilized 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 they may impact our operations, but enactment of additional laws or regulations could increase our operating costs.

Recent federal budget proposals have included provisions which could potentially increase and accelerate the payment of federal income taxes of independent producers of natural gas and oil. Proposals that would significantly affect us would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. 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, federal legislation was enacted that, among other things, establishes federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities that participate in that market. The new legislation requires the SEC and the CFTC to promulgate rules and regulations implementing the new legislation and, as of the date of this report, most of the key implementing regulations have not been adopted. Accordingly, it is not possible at this time to predict the impact of the new legislation on our hedging program. It is possible, however, that the legislation will make hedging more expensive, uneconomic or unavailable, which could lead to increased costs or commodity price volatility or a combination of both.

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 prospect 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, 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 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

Table of Contents

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, the oil spill in the Gulf of Mexico, the explosion of natural gas transmission lines in California and elsewhere and concerns raised by advocacy groups about hydraulic fracturing, may lead to increased regulatory scrutiny which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These action 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

Table of Contents

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 (1) 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 (2) 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 63% of which are considered undeveloped), which encompasses substantially all of the Company s acreage of proved developed and undeveloped natural gas and oil production properties. Approximately 530,000 of these acres are located in the Marcellus. 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, 2011, the Company estimated its total proved reserves to be 5,365 Bcfe, consisting of proved developed producing reserves of 2,502 Bcfe, proved developed non-producing reserves of 464 Bcfe and proved undeveloped reserves of 2,399 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 twenty-three 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, production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems and the reserve roll forward 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, 2011. 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 22 (unaudited) to the Consolidated Financial Statements.

Table of Contents

In 2011, the Company commenced drilling operations (spud or drilled) on 105 gross horizontal wells with an aggregate of approximately 500,000 feet of pay in the Marcellus play. Total proved reserves in the Marcellus play increased 19% to 3.4 Tcfe in 2011 as a result of the Company s 2011 drilling program. In the Huron play, the Company drilled 115 gross horizontal wells with an aggregate of approximately 550,000 feet of pay during 2011. Total proved reserves in the Huron play (including vertical non-shale formations) decreased 19% to 1.8 Tcfe, as the Company 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 2011. The CBM play had total proved reserves of 0.2 Tcfe at December 31, 2011, slightly up from 2010. Natural gas production sales volumes in 2011 from the Marcellus, Huron and CBM plays were 81.6 Bcfe, 99.1 Bcfe and 13.7 Bcfe, respectively. Over the past three years, the Company has experienced a 99% developmental drilling success rate.

Natural gas, NGL and crude oil production and pricing:

	For the year ended December 31,		
	2011	**2010**	**2009**
Natural Gas:			
MMcf produced	185,994	127,847	95,779
Average wellhead sales price to EQT Corporation per Mcf (including hedges)	$ 4.76	$ 4.99	$ 5.47
NGLs:			
Thousands of Bbls produced	3,076	2,712	2,219
Average sales price per Bbl	$ 52.56	$ 48.76	$ 35.21
Crude Oil:			
Thousands of Bbls produced	208	120	99
Average sales price per Bbl	$ 81.58	$ 70.23	$ 49.62

The Company s average per unit production cost, excluding production taxes, of natural gas and crude oil during 2011, 2010 and 2009 was $0.20, $0.24 and $0.30 per Mcfe, respectively. At December 31, 2011, the Company had approximately 57 multiple completion wells.

	Natural Gas	**Oil**
Total productive wells at December 31, 2011:		
Total gross productive wells	14,487	6
Total net productive wells	10,571	6
Total in-process wells at December 31, 2011:		
Total gross in-process wells	105	
Total net in-process wells	98	

Summary of proved oil and gas reserves as of December 31, 2011 based on average fiscal-year prices:	**(MMcf)**	**(MBbls)**
Developed	2,948,546	2,931
Undeveloped	2,398,840	

Total acreage at December 31, 2011:	
Total gross productive acres	1,300,324
Total net productive acres	1,133,122
Total gross undeveloped acres	2,170,225
Total net undeveloped acres	1,891,168

As of December 31, 2011, the Company did not have any reserves that have been classified as proved undeveloped reserves for more than five years.

Table of Contents

Certain lease and acquisition agreements require the Company to drill 6 wells in the Marcellus formation in 2012 within specified acreage. The Company intends to satisfy such requirements to the extent that they fit into its 2012 Marcellus development program, however approximately 200 acres could expire in so much as they currently fall outside of its priority development areas. As of December 31, 2011 and not including the above, leases associated with 8,988 gross undeveloped acres expire in 2012 if they are not renewed; however, the Company has an active lease renewal program in areas targeted for development.

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

	For the year ended December 31,		
	2011	**2010**	**2009**
Exploratory wells:			
Productive			
Dry			1.0
Development wells:			
Productive	211.2	392.1	535.6
Dry	2.0	3.0	2.0

Selected data by state (at December 31, 2011 unless otherwise noted):

	Kentucky	**West Virginia**	**Virginia**	**Pennsylvania**	**Ohio**	**Total**
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
Natural gas and oil production (MMcfe) 2009	50,959	27,069	24,624	2,276		104,928
Average net revenue interest (%)	95.0%	86.5%	48.1%	86.7%		81.3%
Total gross productive wells	5,550	4,925	3,240	778		14,493
Total net productive wells	4,696	3,166	1,941	774		10,577
Total gross productive acreage	538,320	421,044	272,400	68,560		1,300,324
Total gross undeveloped acreage	916,024	783,099	272,157	196,642	2,303	2,170,225
Total gross acreage	1,454,344	1,204,143	544,557	265,202	2,303	3,470,549
Total net productive acreage	469,100	366,914	229,503	67,605		1,133,122
Total net undeveloped acreage	915,413	656,722	122,259	194,471	2,303	1,891,168
Total net acreage	1,384,513	1,023,636	351,762	262,076	2,303	3,024,290
Proved developed producing reserves (Bcfe)	1,116	723	330	333		2,502
Proved developed non-producing reserves (Bcfe)	12	120		332		464
Proved undeveloped reserves (Bcfe)		786		1,613		2,399
Proved developed and undeveloped reserves (Bcfe)	1,128	1,629	330	2,278		5,365

Gross proved undeveloped drilling locations	182	254	436
Net proved undeveloped drilling locations	182	251	433

Table of Contents

Capital expenditures at EQT Production totaled $1,088 million during 2011, including $57.2 million for the acquisition of undeveloped property and $92.6 million of liabilities assumed in the ANPI transaction. During the year, the Company converted 187 Bcfe of proved undeveloped reserves to proved developed reserves and added 452 Bcfe of proved developed reserves which were not previously categorized as proved undeveloped reserves. New proved undeveloped reserves of 822 Bcfe were added during 2011 while 921 Bcfe were reduced in accordance with the Company's decision to focus on Marcellus drilling over the next five years and to comply with the SEC five year guidance. As of December 31, 2011, the Company's proved undeveloped reserves totaled 2.4 Tcfe and all were associated with the development of the Marcellus play. All proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2016.

The Company s 2011 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 694 Bcfe exceeded the 2011 production of 199 Bcfe.

Wells located in Kentucky are primarily in Huron formation 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 7,000 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 10,450 miles of gathering line and 248 compressor units with approximately 245,000 horsepower of installed capacity, as well as other general property and equipment.

	Kentucky	**West Virginia**	**Virginia**	**Pennsylvania**	**Total**
Approximate miles of gathering line	3,550	4,350	1,700	850	10,450

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

EQT Midstream also 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 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 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.

Equitable 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.

Table of Contents

Item 3. Legal Proceedings

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.

Item 4. Mine Safety and Health Administration Data

Not appliable.

Table of Contents

Executive Officers of the Registrant (as of February 16, 2012)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Theresa Z. Bone (48)	Vice President and Corporate Controller (2007)	Elected to present position July 2007; Vice President and Controller of Equitable Utilities from December 2004 until July 2007.
Philip P. Conti (52)	Senior Vice President and Chief Financial Officer (2000)	Elected to present position February 2007; Vice President and Chief Financial Officer from January 2005 to February 2007.
Randall L. Crawford (49)	Senior Vice President and President, Midstream, Commercial and Distribution (2003)	Elected to present position in April 2010; Senior Vice President Midstream and Distribution from January 2008 to April 2010. Senior Vice President, and President, Equitable Utilities from February 2007 to December 2007; Vice President, and President, Equitable Utilities from February 2004 to February 2007.
Martin A. Fritz (47)	Vice President and President, Midstream Operations (2006)	Elected to current position April 2010; Vice President and President Midstream from January 2008 to April 2010. Vice President and Chief Administrative Officer from February 2007 to December 2007; Vice President and Chief Information Officer from April 2006 to February 2007.
Lewis B. Gardner (54)	General Counsel and Vice President, External Affairs(2008)	Elected to present position April 2008; Managing Director External Affairs and Labor Relations from January 2008 to March 2008; Senior Counsel - Director Employee and Labor Relations from March 2004 to December 2007.
M. Elise Hyland (52)	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 July 2007 to January 2008; Senior Vice President, Customer Operations Equitable Gas Company from March 2004 to June 2007.
Charlene Petrelli (51)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007; Vice President, Human Resources from January 2003 to February 2007.
David L. Porges (54)	Chairman, President and Chief Executive Officer (1998)	Elected to present position May 2011; President, Chief Executive Officer and Director, April 2010 through May 2011; President and Chief Operating Officer from February 2007 to April 2010; Vice Chairman and Executive Vice President, Finance and Administration from January 2005 to February 2007.
Steven T. Schlotterbeck (46)	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; Executive Vice President, Exploration and Development, Equitable Production Company (EPC) from July 2007 to December 2007; Managing Director, Exploration and Production Planning and Development, EPC from January 2006 to June 2007.

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.

Table of Contents

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, are summarized as follows (in U.S. dollars per share):

	2011			2010		
	High	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st Quarter	$ 49.99	$ 43.18	$ 0.22	$ 47.43	$ 39.78	$ 0.22
2nd Quarter	54.25	45.68	0.22	46.06	35.80	0.22
3rd Quarter	65.97	47.86	0.22	39.50	32.23	0.22
4th Quarter	73.10	49.54	0.22	45.23	36.01	0.22

As of January 31, 2012, there were 3,249 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 on business conditions, such as the Company s lines of business, result of operations and financial conditions, strategic direction and other factors.

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, 2011:

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 2011 (October 1 October 31)	2,105.93	$ 62.29		
November 2011 (November 1 November 30)	1,721.04	$ 59.40		
December 2011 (December 1 December 31)	495.63	$ 55.63		
Total	4,322.60	$ 60.38		

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

Table of Contents

Stock Performance Graph

The following graph compares the most recent five-year cumulative total return attained by shareholders on the Company s common stock with the cumulative total returns of the S&P 500 index and two customized peer groups of twenty companies (the Old Self-Constructed Peer Group) and twenty-five companies (the New Self-Constructed Peer Group), respectively, whose individual companies are listed in footnotes (1) and (2) below, respectively. An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2006 in the Company s common stock, in the S&P 500 index, and in each peer group. Relative performance is tracked through December 31, 2011.

	12/06	12/07	12/08	12/09	12/10	12/11
EQT Corporation	**100.00**	**129.86**	**83.26**	**111.51**	**116.37**	**144.50**
S&P 500	**100.00**	**105.49**	**66.46**	**84.05**	**96.71**	**98.75**
Old Self-Constructed Peer Group (1)	**100.00**	**123.67**	**77.24**	**112.53**	**125.47**	**156.65**

New Self-Constructed Peer Group (2)	**100.00**	**131.59**	**77.30**	**119.33**	**130.51**	**137.45**

(1) The Company s old self-constructed peer group includes twenty companies, which are: Atlas Energy Resources LLC, Cabot Oil & Gas Corp., Chesapeake Energy Corp., CNX Gas Corporation, El Paso Corp., Enbridge Inc., Energen Corp., Markwest Energy Partners Limited Partner, MDU Resources Group Inc., National Fuel Gas Company, Oneok Inc., Penn Virginia Corp., Questar Corp., Range Resources Corp., Sempra Energy, Southern Union Company, Southwestern Energy Company, Spectra Energy Corp., Transcanada Corp. and

Table of Contents

Williams Companies Inc. Atlas Energy Resources LLC was acquired during 2009 and is included in the calculation from December 31, 2005 through December 31, 2008, at which time it is removed from the peer group calculation. CNX Gas Corporation was acquired during 2010 and is included in the calculation from December 31, 2005 through December 31, 2009, at which time it is removed from the peer group calculation. Questar Corporation was calculated using historical split adjusted pricing data.

(2) The Company s new self-constructed peer group includes twenty-five companies which are: Cabot Oil & Gas Corp., Chesapeake Energy Corp., Cimarex Energy Company, Consol Energy Inc, Energen Corp., EOG Resources Inc, Exco Resources Inc, Markwest Energy Partners Limited Partner, MDU Resources Group Inc, National Fuel Gas Company, Nstar, Oneok Inc, Penn Virginia Corp., Pioneer Natural Resources Company, Plains Exploration & Production Company, Questar Corp., Quicksilver Resources Inc, Range Resources Corp., Sempra Energy, SM Energy Company, Southwestern Energy Company, Spectra Energy Corp., Ultra Petroleum Corp., Whiting Petroleum Corp. and Williams Companies Inc. In future years, the Company generally will use this new self-constructed peer group because the businesses operated by this self-constructed peer group more closely reflect the businesses engaged in by the Company and this peer group is the same as the peer group for the Company s 2012 Executive Performance Incentive Program.

Table of Contents

Item 6. Selected Financial Data

	As of and for the years ended December 31,				
	2011	2010	2009	2008	2007
	(Thousands, except per share amounts)				
Operating revenues	$ 1,639,934	$ 1,374,395	$ 1,311,356	$ 1,609,384	$ 1,382,846
Net income	$ 479,769	$ 227,700	$ 156,929	$ 255,604	$ 257,483
Earnings per share					
Basic	$ 3.21	$ 1.58	$ 1.20	$ 2.01	$ 2.12
Diluted	$ 3.19	$ 1.57	$ 1.19	$ 2.00	$ 2.10
Total assets	$ 8,772,719	$ 7,098,438	$ 5,957,257	$ 5,329,662	$ 3,936,971
Long-term debt	$ 2,746,942	$ 1,949,200	$ 1,949,200	$ 1,249,200	$ 753,500
Cash dividends declared per share of common stock	$ 0.880	$ 0.880	$ 0.880	$ 0.880	$ 0.880

See Item 1A, Risk Factors and Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Notes 2, 5 and 6 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 2011 EQT achieved record results. Highlights for 2011 include:

- Record annual production sales volumes of 194.4 Bcfe, 44% higher than in 2010;

- Marcellus proved reserves increased by 19%;

- Unit lease operating expense, excluding production taxes (LOE), decreased 17% in 2011, to $0.20 per Mcfe. Including production taxes, LOE was $0.40 per Mcfe; and

- Record EQT Midstream throughput and operating income.

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 and $156.9 million, $1.19 per diluted share, for 2009. In 2011, the Company recorded $128.3 million of after-tax gains on dispositions related to the sales of Langley and Big Sandy as described in Item I, Business.

Operating income increased to $861.3 million in 2011 from $470.5 million in 2010. In addition to the $202.9 million pre-tax 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.

Table of Contents

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.

The $70.8 million increase in net income from 2009 to 2010 was primarily attributable to increased production sales volumes, higher gathering revenues, increased net revenues for NGLs, lower long-term incentive compensation expense and lower exploration expense. These favorable variances were partially offset by increased depreciation, depletion and amortization, lower average wellhead sales prices and lower storage and marketing revenues.

EQT revenues for 2010 increased approximately 5% compared to 2009 revenues. Production sales volumes increased more than 34% from 2009 primarily as a result of increased production from the 2009 and 2010 drilling programs partially offset by the normal production decline in the Company s producing wells. Gathered volumes increased due to the Company s production growth and infrastructure expansion. Residential revenues increased as a result of the Company s base rate increases in February 2009 and August 2010. These increases were partially offset by a 3% decline in the average wellhead sales price to EQT Corporation as a result of lower hedge prices year-over-year which more than offset slightly increased natural gas commodity and NGL prices and a 7% decline in storage and marketing revenues primarily resulting from lower margins on asset optimization activities.

Operating expenses for 2010 decreased approximately 5% compared to 2009. This decline was primarily attributable to a $108.0 million decrease in purchased gas costs due to lower recoverable commodity costs, a $39.3 million decrease in long-term incentive compensation expense and a $12.5 million decrease in the Company s exploration program. The decrease in exploration expense was primarily a result of a reduction in the level of purchase and interpretation of seismic data for unproved properties. These decreases were partially offset by higher depletion resulting from increased investment in oil and gas producing properties.

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.

Table of Contents

EQT CORPORATION

OPERATIONAL DATA	2011	2010	% change 2011 - 2010	2009	% change 2010 - 2009
	Years Ended December 31,				
Average wellhead sales price to EQT Corporation:					
Natural gas excluding hedges ($/Mcf)	$ 4.21	$ 4.44	(5.1)	$ 4.02	10.4
Hedge impact ($/Mcf of natural gas) (a)	$ 0.55	$ 0.55		$ 1.45	(62.1)
Natural gas including hedges ($/Mcf)	$ 4.76	$ 4.99	(4.6)	$ 5.47	(8.8)
NGLs ($/Bbl)	$ 52.56	$ 48.76	7.8	$ 35.21	38.5
Crude oil ($/Bbl)	$ 81.58	$ 70.23	16.2	$ 49.62	41.5
Total ($/Mcfe)	$ 5.37	$ 5.62	(4.4)	$ 5.80	(3.1)
Less revenues to EQT Midstream ($/Mcfe)	$ 1.33	$ 1.69	(21.3)	$ 1.69	
Average wellhead sales price to EQT Production ($/Mcfe)	$ 4.04	$ 3.93	2.8	$ 4.11	(4.4)
NYMEX natural gas ($/Mcf)	$ 4.04	$ 4.39	(8.0)	$ 3.99	10.0
Natural gas sales volumes (MMcf)	181,566	123,440	47.1	90,951	35.7
NGL sales volumes (Mbbls)	3,076	2,712	13.4	2,219	22.2
Crude oil sales volumes (Mbbls)	208	120	73.3	99	21.2
Total production sales volumes (MMcfe) (b)	194,393	134,614	44.4	100,100	34.5
Capital expenditures (thousands) (c)	$ 1,366,894	$ 1,477,619	(7.5)	$ 963,908	53.3

(a) All hedges are related to natural gas.

(b) NGLs were converted to Mcfe at the rate of 3.76 Mcfe per barrel, 3.86 Mcfe per barrel and 3.86 Mcfe per barrel based on the liquids content for the years ended December 31, 2011, 2010 and 2009 respectively, and crude oil was converted to Mcfe at the rate of six Mcfe per barrel for all periods.

(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.

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. Interest, income taxes and other income 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 $29.3 million, $15.1 million and $62.2 million, respectively, were not allocated to the operating segments for the years ended December 31, 2011, 2010 and 2009.

Table of Contents

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 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 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 2 to the Consolidated Financial Statements.

EQT Production

Results of Operations

	Years Ended December 31,				
	2011	**2010**	**% change 2011 - 2010**	**2009**	**% change 2010 - 2009**
OPERATIONAL DATA					
Natural gas, NGL and crude oil production (MMcfe) (a)	198,821	139,021	43.0	104,928	32.5
Company usage, line loss (MMcfe)	(4,428)	(4,407)	0.5	(4,828)	(8.7)
Total production sales volumes (MMcfe)	194,393	134,614	44.4	100,100	34.5
Average daily sales volumes (MMcfe/d)	533	369	44.4	274	34.7
Sales volume detail (MMcfe):					
Horizontal Marcellus Play	81,602	25,474	220.3	3,186	699.6
Horizontal Huron Play	40,081	38,816	3.3	26,779	44.9
CBM Play	13,682	13,493	1.4	12,313	9.6
Other (vertical non-CBM)	59,028	56,831	3.9	57,822	(1.7)
Total production sales volumes	194,393	134,614	44.4	100,100	34.5
Average wellhead sales price to EQT Production ($/Mcfe)	$ 4.04	$ 3.93	2.8	$ 4.11	(4.4)
Lease operating expenses, excluding production taxes (LOE) ($/Mcfe)	$ 0.20	$ 0.24	(16.7)	$ 0.30	(20.0)
Production taxes ($/Mcfe)	$ 0.20	$ 0.24	(16.7)	$ 0.30	(20.0)
Production depletion ($/Mcfe)	$ 1.25	$ 1.26	(0.8)	$ 1.06	18.9
Depreciation, depletion and amortization (DD&A) (thousands):					

Production depletion	$ 248,286	$ 175,629	41.4	$ 111,371	57.7
Other DD&A	8,858	8,070	9.8	6,053	33.3
Total DD&A (thousands)	$ 257,144	$ 183,699	40.0	$ 117,424	56.4
Capital expenditures (thousands) (b)	$1,087,840	$1,245,914	(12.7)	$ 717,356	73.7

Table of Contents

	Years Ended December 31,				
	2011	2010	% change 2011 - 2010	2009	% change 2010 - 2009
FINANCIAL DATA (thousands)					
Total net operating revenues	$ 791,285	$ 537,657	47.2	$ 420,990	27.7
Operating expenses:					
LOE	40,369	33,784	19.5	31,228	8.2
Production taxes (c)	40,542	33,630	20.6	31,750	5.9
Exploration expense	4,932	5,368	(8.1)	17,905	(70.0)
Selling, general and administrative (SG&A)	61,200	57,689	6.1	36,815	56.7
DD&A	257,144	183,699	40.0	117,424	56.4
Total operating expenses	404,187	314,170	28.7	235,122	33.6
Operating income	$ 387,098	$ 223,487	73.2	$ 185,868	20.2

(a) Natural gas, NGL and oil production represented 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, Company usage and line loss.

(b) 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.

(c) Production taxes include severance and production-related ad valorem and other property taxes.

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 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, as well as the acquisition of producing properties associated with the ANPI transaction, as described in Item 1, Business, 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 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 the current year 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 the current year 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

Table of Contents

agreements. Lower costs for road and location maintenance due to less severe weather in the current year 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.

Year Ended December 31, 2010 vs. December 31, 2009

EQT Production s operating income totaled $223.5 million for 2010 compared to $185.9 million for 2009, an increase of $37.6 million between years, primarily due to increased production sales volumes, partially offset by a lower average wellhead sales price and an increase in depletion and SG&A expenses.

Total operating revenues were $537.7 million for 2010 compared to $421.0 million for 2009. The $116.7 million increase in operating revenues was due to increased sales volumes which more than offset lower average realized wellhead sales prices. The increase in gas sales volumes was the result of increased production from the 2009 and 2010 drilling programs, primarily in the Marcellus and Huron plays. This increase was partially offset by the normal production decline in the Company s wells. The $0.18 per Mcfe decrease in the average wellhead sales price to EQT Production was primarily due to lower hedging gains and lower hedged gas sales volumes compared to 2009, partially offset by a 10% increase in the average NYMEX price and a higher sales price for NGLs.

Operating expenses totaled $314.2 million for 2010 compared to $235.1 million for 2009. The 34% increase in operating expenses was primarily the result of increases of $66.3 million in DD&A, $20.9 million in SG&A and $2.6 million in LOE partially offset by a decrease of $12.5 million in exploration expense. The increase in DD&A was primarily due to increased depletion expense resulting from increases in the blended depletion unit rate and volume. The $0.20 per Mcfe increase in the blended depletion unit rate was primarily attributable to the increased investment in oil and gas producing properties. The increase in SG&A was primarily due to the reversal of reserves in the prior year for certain legal disputes; higher personnel costs including incentive compensation and hiring and relocation costs, a portion of which was recorded at headquarters in prior years; a charge for the buy-out of excess contractual capacity for the processing and disposal of salt water; and an increase in professional fees. Despite the 20% decrease in the average LOE per Mcfe, total LOE increased as a result of increased activity in the Marcellus play in the current year. These factors were partially offset by a decrease in exploration expense due to a reduction in geophysical activity compared to the prior year as well as an impairment charge in 2009 on an exploratory Utica well.

Table of Contents

EQT Midstream

Results of Operations

	Years Ended December 31, 2011	2010	% change 2011 - 2010	2009	% change 2010 2009
OPERATIONAL DATA					
Gathering and processing:					
Gathered volumes (BBtu)	258,179	195,642	32.0	161,480	21.2
Average gathering fee ($/MMBtu)	$ 0.97	$ 1.11	(12.6)	$ 1.04	6.7
Gathering and compression expense ($/MMBtu) (a)	$ 0.30	$ 0.37	(18.9)	$ 0.42	(11.9)
Transmission pipeline throughput (BBtu)	159,384	109,165	46.0	84,132	29.8
Net operating revenues (thousands):					
Gathering	$ 249,607	$ 212,170	17.6	$ 165,519	28.2
Transmission	90,405	84,190	7.4	76,749	9.7
Storage, marketing and other	64,614	100,097	(35.4)	107,530	(6.9)
Total net operating revenues	$ 404,626	$ 396,457	2.1	$ 349,798	13.3
Unrealized (losses) gains on derivatives and inventory (thousands) (b)	$ (755)	$ (379)	99.2	$ 206	(284.0)
Capital expenditures (thousands)	$ 242,886	$ 193,128	25.8	$ 201,082	(4.0)
FINANCIAL DATA (thousands)					
Total operating revenues	$ 525,345	$ 580,698	(9.5)	$ 465,444	24.8
Purchased gas costs	120,719	184,241	(34.5)	115,646	59.3
Total net operating revenues	404,626	396,457	2.1	349,798	13.3
Operating expenses:					
Operating and maintenance (O&M)	83,907	107,601	(22.0)	95,164	13.1
SG&A	49,901	48,127	3.7	47,146	2.1
DD&A	57,135	61,863	(7.6)	53,291	16.1
Total operating expenses	190,943	217,591	(12.2)	195,601	11.2
Gain on dispositions	202,928		100.0		
Operating income	$ 416,611	$ 178,866	132.9	$ 154,197	16.0

(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.

Table of Contents

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 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 sold Big Sandy Pipeline.

Storage, marketing and other net 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 natural gas liquids 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 by $55.4 million or 10%, 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 is 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.

Year Ended December 31, 2010 vs. December 31, 2009

EQT Midstream s operating income totaled $178.9 million for 2010 compared to $154.2 million for 2009. The $24.7 million increase in operating income was primarily the result of increased gathering volumes and gathering rates, partially offset by decreased storage, marketing and other net operating revenues and increased operating expenses.

Total net operating revenues were $396.5 million for 2010 compared to $349.8 million for 2009. The $46.7 million increase in total net operating revenues was due to a $46.7 million increase in gathering net operating revenues and a $7.4 million increase in transmission net operating revenues, partially offset by a $7.4 million decrease in storage, marketing and other net operating revenues.

Gathering net operating revenues increased due to a 21% increase in gathered volumes as well as a 7% increase in the average gathering fee. The increased revenue was driven primarily by higher Marcellus volumes from EQT Production.

Table of Contents

Transmission net revenues in 2010 increased from the prior year primarily 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, which came on-line during the fourth quarter of 2010.

The decrease in storage, marketing and other net revenues was primarily due to decreased margins and volumes of third-party marketing that utilized pipeline capacity, less volatility in seasonal price spreads and decreased basis differentials which in 2009 had a positive impact on the Company. This decrease was partially offset by an increase in NGL processing net revenues primarily due to an increase in average NGL sales price.

Total operating revenues increased by $115.3 million, or 25%, primarily as a result of increased marketed volumes due to higher Marcellus activity and higher gathered volumes. Total purchased gas costs also increased as a result of higher Marcellus activity.

Operating expenses totaled $217.6 million for 2010 compared to $195.6 million for 2009. The increase in operating expenses was primarily due to increases of $12.4 million in O&M and $8.6 million in DD&A. The increase in O&M is primarily due to higher electricity, labor, and non-income taxes associated with the growth of the business as well as a $2.6 million loss on compressor decommissioning at Langley. The increase in DD&A was primarily due to the increased investment in gathering and transmission infrastructure.

Table of Contents

Distribution

Results of Operations

	Years Ended December 31,				
	2011	2010	% change 2011 - 2010	2009	% change 2010 2009
OPERATIONAL DATA					
Heating degree days (30 year average = 5,710)	5,189	5,516	(5.9)	5,474	0.8
Residential sales and transportation volume (MMcf)	22,333	23,132	(3.5)	23,098	0.1
Commercial and industrial volume (MMcf)	28,752	27,124	6.0	30,521	(11.1)
Total throughput (MMcf)	51,085	50,256	1.6	53,619	(6.3)
Net operating revenues (thousands):					
Residential	$ 115,912	$ 117,418	(1.3)	$ 111,007	5.8
Commercial & industrial	48,968	48,614	0.7	47,432	2.5
Off-system and energy services	22,672	21,365	6.1	21,545	(0.8)
Total net operating revenues	$ 187,552	$ 187,397	0.1	$ 179,984	4.1
Capital expenditures (thousands)	$ 31,313	$ 36,619	(14.5)	$ 33,707	8.6
FINANCIAL DATA (thousands)					
Total operating revenues	$ 419,678	$ 474,143	(11.5)	$ 560,283	(15.4)
Purchased gas costs	232,126	286,746	(19.0)	380,299	(24.6)
Net operating revenues	187,552	187,397	0.1	179,984	4.1
Operating expenses:					
O & M	43,383	44,047	(1.5)	43,663	0.9
SG&A	31,524	35,994	(12.4)	35,028	2.8
DD&A	25,747	24,174	6.5	22,375	8.0
Total operating expenses	100,654	104,215	(3.4)	101,066	3.1
Operating income	$ 86,898	$ 83,182	4.5	$ 78,918	5.4

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.

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 National Oceanic and Atmospheric Administration average. Commercial and industrial net 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

Table of Contents

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.

Year Ended December 31, 2010 vs. December 31, 2009

Distribution s operating income totaled $83.2 million for 2010 compared to $78.9 million for 2009. The increase in operating income was primarily due to an increase in base rates which was partially offset by higher operating expenses.

Net operating revenues were $187.4 million for 2010 compared to $180.0 million for 2009. The $7.4 million increase in net operating revenues was primarily the result of an increase in residential net operating revenues. Net operating revenues from residential customers increased $6.4 million as a result of the approval of the Company s Pennsylvania base rate increase in late February 2009 as well as the approval of the Company s West Virginia base rate increase in August 2010. Commercial and industrial net revenues increased $1.2 million due to higher base rates and an increase in performance-based revenues, partially offset by a decrease in usage by one industrial customer. High volume sales to this industrial customer had low unit margins and the decrease in sales volumes did not ratably impact total net operating revenues. Off-system and energy services net operating revenues decreased due to lower margins on asset optimization activities, partially offset by increased gathering revenue as a result of higher rates. A decrease in the commodity component of residential tariff rates and a decrease in gas costs associated with asset optimization transactions resulted in a decrease in both total operating revenues and purchased gas costs.

Operating expenses totaled $104.2 million for 2010 compared to $101.1 million for 2009. The $3.1 million increase in operating expenses was primarily the result of higher bad debt and depreciation and amortization expense. The increase in bad debt expense from 2009 to 2010 was primarily the result of a favorable one-time adjustment in the allowance for uncollectible accounts in 2009 due to the recovery of CAP costs associated with the approval of the Pennsylvania rate case settlement. These increases were partially offset by an increase in accruals for certain non-income tax reserves in 2009 and a decrease in incentive compensation costs in 2010. The increase in DD&A expense was primarily the result of increased capital expenditures.

Other Income Statement Items

Other Income

Years Ended December 31,

	2011	2010 (Thousands)	2009
Other income	$34,138	$12,898	$8,585

Other income includes equity in earnings of nonconsolidated investments, primarily the Company s investment in Nora Gathering LLC, of $7.2 million, $9.7 million and $6.5 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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 2010 also included a $2.1 million gain on sales of available-for-sale securities.

Table of Contents

Interest Expense

	Years Ended December 31, 2011	2010	2009
		(Thousands)	
Interest expense	$136,328	$128,157	$111,779

Interest expense increased by $8.2 million from 2010 to 2011 as a result of the Company s 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.

Interest expense increased by $16.4 million from 2009 to 2010 primarily due to the full year of expense incurred on the $700 million of 8.125% notes issued in May 2009. This increase was partially offset by a $4.4 million increase in capitalized interest primarily due to the capitalization of interest on Marcellus well development beginning in 2010, reflecting the longer time to flow gas and increased investment associated with the multi-well pads.

Weighted average annual interest rates on the Company s long-term debt were 6.8%, 6.8%, and 6.5% for 2011, 2010 and 2009, respectively. Weighted average annual interest rates on the Company s short-term debt were 1.81%, 0.7% and 0.7% for 2011, 2010 and 2009, respectively.

Income Taxes

	Years Ended December 31, 2011	2010	2009
		(Thousands)	
Income Taxes	$279,360	$127,520	$96,668

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 2011was primarily the result of the tax benefit for these repair costs being higher in 2010 than in 2011. State income taxes were also 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.

Income tax expense increased by $30.9 million from 2009 to 2010 as a result of higher pre-tax income which was partly offset by a lower effective tax rate. During 2010, the Company s effective income tax rate decreased from 38.1% to 35.9%. The higher tax rate in 2009 was primarily the result of the impact in 2009 of certain nondeductible expenses and the loss of certain prior year deductions as a result of carrying 2009 losses back to receive a cash refund of taxes paid. These higher rates in 2009 were partially mitigated by a regulatory asset recorded to recover deferred taxes caused by an accounting method change that deducts as repairs certain costs capitalized for financial accounting purposes in 2009. Rates were also lower in 2010 due to a reduction of the reserve for uncertain tax positions.

The Company was in an overall federal tax net operating loss position for 2011, 2010 and 2009 and expects to pay minimal federal income taxes for the next few years as the Company s drilling program in Appalachia continues to generate intangible drilling cost deductions, unless tax laws change or the Company incurs a taxable gain from a discrete transaction. In 2011 the sales of Langley and Big Sandy resulted in the Company paying federal alternative minimum tax and state taxes totaling approximately $49.6 million. For federal income tax purposes, the Company deducts approximately 84% of drilling costs as intangible drilling costs (IDC) in the year incurred. The primary reasons for the Company s net operating loss are the IDC deduction resulting from the Company s drilling program and the accelerated tax deprecation for expansion of gathering infrastructure which

Table of Contents

provide tax deductions in excess of book deductions. See Note 7 to the Consolidated Financial Statements for further discussion of the Company s income taxes.

Outlook

The Company is committed to profitably developing its Marcellus reserves through environmentally responsible, cost-effective, technologically-advanced horizontal drilling. The market price for natural gas can be volatile as demonstrated by significant declines in late 2011 and early 2012. In response to these lower prices, the Company has suspended drilling new Huron wells. Wells currently in progress will be completed and turned-in-line. 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.

After adjusting for the change in drilling plans for 2012, capital expenditures for well development (primarily drilling) in 2012 are expected to be approximately $1,055 million to support the drilling of approximately 158 gross wells, including 146 gross Marcellus wells and 12 gross Huron wells which were either spud in January 2012 or are required to maintain lease rights. Sales volumes are expected to be between 250 and 255 Bcfe for an anticipated production sales volume growth of approximately 30% in 2012.

In addition, the Company plans to spend $365 million on midstream infrastructure in 2012 to support this production growth and expects gathering and transmission volumes to increase as a result of this expansion. EQT Midstream plans to add 445 MMcfe per day of incremental gathering capacity and 700 MMcfe per day of transmission capacity in 2012. This includes 300 MMcfe per day of transmission volumes from the Sunrise Pipeline project which is expected to go into service in 2012.

The Company currently believes that the 2012 capital spending plan will be funded by cash flow generated from operations and cash on hand.

Capital Resources and Liquidity

The Company s primary sources of cash for 2011 were cash flows from operating activities, and proceeds from the issuance of senior debt and asset sales. The Company s primary use of cash in 2011 was for capital expenditures.

Operating Activities

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.

The Company s net cash provided by operating activities during 2010 was $789.7 million compared to $725.7 million for 2009. The increase in cash flows provided by operating activities was primarily attributable to higher earnings resulting from increased production volumes and higher NGL prices partially offset by lower realized natural gas prices.

Investing Activities

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 discussion of capital expenditures below.

Table of Contents

Cash flows used in investing activities totaled $1,239.4 million for 2010 as compared to $985.5 million for 2009. The increase in cash flows used in investing activities was primarily attributable to an increase in capital expenditures to $1,246.9 million in 2010 from $963.9 million in 2009. See discussion of capital expenditures below. This increase was partially offset by proceeds from the sale of available for sale securities and reduced capital contributions to Nora Gathering, LLC.

Capital Expenditures

	2012 Forecast		2011 Actual		2010 Actual		2009 Actual	
Well development (primarily drilling)	$	1,055 million	$	938 million	$	888 million	$	686 million
Property acquisitions	$		$	150 million	$	358 million	$	31 million
Midstream infrastructure	$	365 million	$	243 million	$	193 million	$	201 million
Distribution infrastructure and other corporate items	$	35 million	$	36 million	$	39 million	$	46 million
Total	$	1,455 million	$	1,367 million	$	1,478 million	$	964 million
Less: non-cash	$		$	93 million	$	231 million	$	
Total cash capital expenditures	$	1,455 million	$	1,274 million	$	1,247 million	$	964 million

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.

The Company is committed to profitably developing its Marcellus reserves through environmentally responsible, cost-effective, technologically-advanced horizontal drilling. In response to lower prices, the Company suspended drilling new Huron wells in January 2012. Wells currently in progress will be completed and turned-in-line. After adjusting for the change in drilling plans for 2012, capital spending for well development (primarily drilling) is expected to be approximately $1,055 million to support the drilling of approximately 158 gross wells, including 146 gross Marcellus wells and 12 Huron wells which were either spud in January 2012 or are required to maintain lease rights. Sales volumes are expected to be between 250 and 255 Bcfe for an anticipated production sales volume growth of approximately 30% in 2012.

In addition, the Company plans to spend $365 million on midstream infrastructure in 2012 to support its production growth and expects gathering and transmission volumes to increase as a result this expansion. EQT Midstream plans to add 445 MMcfe per day of incremental gathering capacity and 700 MMcfe per day of transmission capacity in 2012. This includes 300 MMcfe per day of transmission volumes from the Sunrise Pipeline project which is expected to go into service in 2012.

Table of Contents

The Company currently believes that 2012 capital expenditures will be funded by cash flow generated from operations and cash on hand.

Financing Activities

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.

Cash flows provided by financing activities totaled $449.7 million for 2010 as compared to $259.8 million for 2009 as the proceeds from the 2010 equity offering exceeded the proceeds of the 2009 debt offering, net of repayment of short-term loans.

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 and the amount and type of derivative commodity instruments executed.

The Company has a $1.5 billion revolving credit facility that matures on December 8, 2014. The facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes, including support of any commercial paper program maintained by the Company from time to time. The credit facility is underwritten by a syndicate of 20 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. The Company s large syndicate group and relatively low percentage of participation by each lender is expected to limit the Company s exposure to problems or consolidation in the banking industry.

As of December 31, 2011, the Company had no loans or letters of credit outstanding under its revolving credit facility. As of December 31, 2010, the Company had loans of $53.7 million and an irrevocable standby letter of credit of $23.5 million outstanding under the revolving credit facility. For the years ended December 31, 2011 and 2010, the Company paid commitment fees averaging approximately 30 basis points and 10 basis points, respectively, to maintain credit availability under the revolving credit facility.

The weighted average interest rate for short-term loans outstanding as of December 31, 2010 was 1.81%. The maximum amount of outstanding short-term loans at any time during the years ended December 31, 2011 and 2010 was $104.0 million and $139.7 million respectively. The average daily balance of short-term loans outstanding during the years ended December 31, 2011 and 2010 was approximately $5.5 million and $24.9 million, respectively, at weighted average annual interest rates of 1.81% and 0.70% respectively.

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

Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at December 31, 2011. Changes in credit ratings may affect the Company s cost of short-term and long-term debt (including interest rates

Table of Contents

and fees under its lines of credit), collateral requirements under derivative instruments and its access to the credit markets.

Rating Service	Unsecured Medium-Term Notes	Commercial Paper
Moody s Investors Service	Baa2	P-2
Standard & Poor s Ratings Services	BBB	A-3
Fitch Ratings Service	BBB	F2

On November 1, 2011, S&P affirmed its rating on EQT and revised the rating outlook from negative to stable. On November 2, 2011, Fitch affirmed its rating on EQT and affirmed the rating outlook at stable. On November 2, 2011, Moody s affirmed its rating on EQT and revised the rating outlook from stable to negative.

The Company s credit ratings may be revised or withdrawn 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, margin deposits on derivative contracts and borrowing costs would increase, counterparties may request additional assurances and the potential pool of investors and funding sources may decrease. The required margin is 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 leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company s credit facility s financial covenants 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, 2011, the Company was in compliance with all existing debt 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 prices swaps, collars and futures.

Table of Contents

The approximate volumes and prices of the Company s hedge position for 2012 through 2014 production are:

	2012	2013	2014
Swaps			
Total Volume (Bcf)	101	70	42
Average Price per Mcf (NYMEX)*	$ 5.20	$ 5.15	$ 4.82
Collars			
Total Volume (Bcf)	21	15	14
Average Floor Price per Mcf (NYMEX)*	$ 6.51	$ 6.12	$ 6.37
Average Cap Price per Mcf (NYMEX)*	$ 11.83	$ 11.80	$ 11.55

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

See the Quantitative and Qualitative Disclosures About Market Risk, in Item 7A and Note 3 to the Company s Consolidated Financial Statements for further discussion.

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 is approximately $213 million as of December 31, 2011, extending at a decreasing amount for approximately 16 years. In addition, the Company agreed to maintain in place certain outstanding payment and performance bonds, letters of credit and other guarantee obligations supporting NORESCO s obligations under certain customer contracts, existing leases and other items with an undiscounted maximum exposure to the Company as of December 31, 2011 of approximately $35 million, of which approximately $34 million relates to bonds that were to have been terminated as of December 31, 2010 for work completed under the underlying contracts. The Company is working with NORESCO to resolve any open matters with respect to these bonds.

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

The Company s distribution operations, transmission and storage operations and a portion of its gathering operations are subject to various forms of regulation as previously discussed. As described in Notes 1 and 10 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

Table of Contents

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	2012	2013-2014	2015-2016	2017+
			(Thousands)		
Purchase obligations	$ 2,331,443	$ 192,157	$ 313,501	$ 352,418	$ 1,473,367
Long-term debt	2,740,885	219,315	34,366	169,004	2,318,200
Interest payments	1,269,473	171,401	319,622	306,182	472,268
Operating leases	200,259	39,875	67,375	26,244	66,765
Pension and other post-retirement benefits	160,230	10,115	19,631	17,596	112,888
Other liabilities	33,678	14,564	19,114		
Total contractual obligations	$ 6,735,968	$ 647,427	$ 773,609	$ 871,444	$ 4,443,488

Purchase obligations primarily 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. Approximately $17.6 million and $3.5 million of these obligations payable in 2012 and 2013, respectively, are believed to be recoverable in customer rates. 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 $61.8 million, $47.5 million and $20.4 million in 2012, 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 $110.1 million as of December 31, 2011. The Company has subleased some of these facilities. Sublease payments to the Company total $30.2 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 $90.2 million as of December 31, 2011.

The other liabilities line represents commitments for total estimated payouts for the 2011 Value Driver Award program. See section titled Critical Accounting Policies Involving Significant Estimates and Note 16 to the Consolidated Financial Statements for further discussion regarding factors that affect the ultimate amount of the payout of these obligations.

As discussed in Note 7 to the Consolidated Financial Statements, the Company had a total liability for the reserve for unrecognized tax benefits at December 31, 2011 of $33.0 million, of which $19.4 million reduces the net operating loss carryover. 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

Contingent Liabilities and Commitments

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 contingent liabilities and commitments.

Table of Contents

Critical Accounting Policies Involving Significant Estimates

The Company s significant accounting policies are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Form 10-K. 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 an aggregated 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 $358.8 million, $445.9 million and $105.9 million in 2011, 2010 and 2009, 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 percent likelihood of being realized upon ultimate settlement. See Note 7 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 realizable upon ultimate settlement. To the extent the Company believes 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, a valuation allowance must be established. Significant management judgment is required in determining any valuation allowance recorded against deferred tax assets and in determining the amount of financial statement benefit to record for uncertain tax positions. 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. In making this determination, 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. Evidence used for the valuation allowance includes information about the Company s current financial position and results of operations for the current and preceding years, as well as all currently available information about future years, including the Company s anticipated future performance, the reversal of deferred tax assets and liabilities and tax planning strategies available to the Company. To the extent that an uncertain tax position or valuation allowance is established or increased or decreased during a period, the Company must include

Table of Contents

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 Commodity 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 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. Changes in the value of fair value hedges are offset with changes in the value of the hedged item (inventory). See Commodity Risk Management above, Item 7A Quantitative and Qualitative Disclosures About Market Risk and Note 3 of 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 spreads, 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.

Table of Contents

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 has awarded share-based compensation in connection with specific programs established under the 1999 and 2009 Long-Term Incentive Plans. The Company treats certain of its programs as liability awards. The actual cost to be recorded for these programs will not be known until the measurement date, requiring the Company to estimate the total expense to be recognized at each reporting date. The Company reviews the assumptions for liability programs 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. Awards that pay in stock are treated as equity awards. These programs may require estimates of total number of shares to be issued depending on performance conditions or may be fixed because of a market condition. Fixed plans require the Company to obtain a valuation which includes assumptions including the expected term of the award, the risk-free rate and expected volatility based on the historical performance of the Company and its peers.

Effective in 2010, the Company adopted the 2010 Executive Performance Incentive Program (2010 EPIP) and the 2010 Stock Incentive Award (2010 SIA) program. The vesting of the units under the 2010 EPIP will occur upon payment after the end of the 3-year performance period. The payment 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 pre-defined peer group over the three-year period ending December 31, 2012 and the level of production sales revenues over the period January 1, 2010 through September 30, 2012. If earned, the 2010 EPIP units are expected to be distributed in Company common stock. The vesting of the awards under the 2010 SIA will occur on the third anniversary of the grant date. The number of awards granted was contingent upon adjusted 2010 earnings before interest, taxes, depreciation and amortization (EBITDA) performance as compared to the Company s annual business plan and individual, business unit and Company value driver performance over the period January 1, 2010 through December 31, 2010. As of December 31, 2011, 295,635 confirmed performance awards were outstanding under the 2010 SIA which are expected to be distributed in Company common stock.

Effective January 1, 2011, the Company adopted the 2011 Volume and Efficiency Program (2011 VEP) and the 2011 Value Driver Award program (2011 VDA). A total of 260,330 awards were granted under the 2011 VEP. The payout of the 2011 VEP awards will range from zero to three times the initial award based on the achievement of pre-determined 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 $48.09 grant date fair value which was equal to the Company s stock price at the grant date of the award.

Under the 2011VDA, 50% of the units awarded vested upon the payment date following the first anniversary of the grant date; the remaining 50% of the units awarded will vest upon the payment date following the second anniversary of the grant date. The payment under this plan varied between zero and 300% of the number of units granted contingent upon adjusted 2011 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

Table of Contents

driver performance over the period January 1, 2011 through December 31, 2011. As of December 31, 2011, 523,347 confirmed awards were outstanding under the 2011 VDA. Half of the awards were distributed in cash in February 2012. The remainder of the awards are expected to vest and be paid in cash in the first quarter of 2013.

Effective 2012, the Company adopted the 2012 Value Driver Award program (2012 VDA) and the 2012 Executive Performance Incentive Program (2012 EPIP). The Company may adopt other plans in the future. The Company has not recorded an obligation under the 2012 VDA, the 2012 EPIP or any potential future plans at December 31, 2011.

The 2009 Long-Term Incentive Plan permits, and the 1999 Long-Term Incentive Plan permitted, the grant of restricted stock awards and non-qualified stock options to employees of the Company. For time restricted stock awards, compensation expense, which is based on the grant date fair value, is recognized in the Company s financial statements over the vesting period. The majority of the time-based restricted shares granted will vest at the end of the three-year period commencing with the date of grant. For non-qualified stock options, compensation expense is based on the grant date fair value and is recognized in the Company s financial statements over the vesting period. 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. 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.

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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Derivative Commodity 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 3 to the Consolidated Financial Statements and under the caption Commodity Risk Management in Management s Discussion and Analysis of Financial Condition and Results of Operations (Item 7) of this Form 10-K. The Company uses derivative commodity instruments that are placed with major financial institutions whose credit worthiness 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 financial instruments is implemented under a set of policies approved by the Company s Corporate Risk Committee and 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 a fixed and variable price for the commodity. The Company also considers other contractual agreements in implementing its commodity hedging strategy.

Table of Contents

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, 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 347 Bcf of natural gas. See the Commodity Risk Management in the Capital Resources and Liquidity sections of Management s Discussion and Analysis of Financial Condition and Results of Operations (Item 7) of this Form 10-K for further discussion.

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

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 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 would 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 earns on cash, cash equivalents and short-term investments and the interest rate it pays on borrowings under the revolving credit facility. All of the Company s long-term borrowings are fixed rate and thus do not expose the Company to fluctuations in its results of operations or liquidity from changes in market interest rates. Changes in interest rates do affect the fair value of the Company s fixed rate debt. See Notes 11 and 12 to the Consolidated Financial Statements for further discussion of the

Company s borrowings and Note 4 to the Consolidated Financial Statements for a discussion of fair value measurements, including the fair value of long-term debt. In August 2011, the Company entered into a forward-starting interest rate swap to mitigate the risk of rising interest rates. See Note 3 to the Consolidated Financial Statements for further discussion of this swap.

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 Commodity Futures Trading Commission regulations are in place to protect exchange participants, including the

Table of Contents

Company, from any potential financial instability of the exchange members. The Company s 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. This includes monitoring current market conditions, counterparty credit spreads 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 81%, or $508.5 million, of OTC derivative contracts outstanding at December 31, 2011 have a positive fair value. All derivative contracts outstanding were with counterparties having an S&P rating of A or above on December 31, 2011.

As of December 31, 2011, the Company was not in default under any derivative contracts and has no knowledge of default by any counterparty to derivative contracts. The Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company s established fair value procedure. The Company 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 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 matures on December 8, 2014. The credit facility is underwritten by a syndicate of 20 financial institutions each of which is obligated to fund its pro-rata portion of any borrowings by the Company. As of December 31, 2011, the Company had no loans or letters of credit outstanding under the facility. No single lender of the 20 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.

Table of Contents

Item 8. Financial Statements and Supplementary Data

Table of Contents

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, 2011 and 2010, and the related statements of consolidated income, common stockholders equity and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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, 2011, 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 16, 2012, expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 16, 2012

Table of Contents

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, 2011, 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, 2011, 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, 2011 and 2010, and the related statements of consolidated income, common stockholders equity and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 16, 2012 expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 16, 2012

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME

YEARS ENDED DECEMBER 31,

	2011	2010	2009
		(Thousands except per share amounts)	
Operating revenues	$ 1,639,934	$ 1,374,395	$ 1,311,356
Operating expenses:			
Purchased gas costs	256,467	252,884	360,898
Operation and maintenance	127,642	152,414	140,003
Production	80,911	67,414	62,978
Exploration	4,932	5,368	17,905
Selling, general and administrative	172,294	155,551	176,703
Depreciation, depletion and amortization	339,297	270,285	196,078
Total operating expenses	981,543	903,916	954,565
Gain on dispositions	202,928		
Operating income	861,319	470,479	356,791
Other income	34,138	12,898	8,585
Interest expense	136,328	128,157	111,779
Income before income taxes	759,129	355,220	253,597
Income taxes	279,360	127,520	96,668
Net income	$ 479,769	$ 227,700	$ 156,929
Earnings per share of common stock:			
Basic:			
Net income	$ 3.21	$ 1.58	$ 1.20
Diluted:			
Net income	$ 3.19	$ 1.57	$ 1.19

See notes to consolidated financial statements.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

YEARS ENDED DECEMBER 31,

	2011	2010 (Thousands)	2009
Cash flows from operating activities:			
Net income	$ 479,769	$ 227,700	$ 156,929
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income taxes	234,019	153,912	234,776
Depreciation, depletion and amortization	339,297	270,285	196,078
Gain on dispositions	(202,928)		
Provision for (recoveries of) losses on accounts receivable	1,581	5,134	(1,263)
Other income	(34,138)	(12,898)	(8,585)
Stock based compensation expense	20,080	14,104	6,768
Reimbursements for tenant improvements	-	4,053	12,212
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues	14,317	(6,330)	66,327
Inventory	1,117	45,104	73,181
Prepaid expenses and other	22,812	126,042	11,836
Accounts payable	42,262	(36,853)	(107,745)
Derivative instruments, at fair value	(4,775)	(7,609)	56,510
Other current liabilities	(15,054)	(2,963)	33,502
Other items, net	16,905	10,059	(4,785)
Net cash provided by operating activities	915,264	789,740	725,741
Cash flows from investing activities:			
Capital expenditures	(1,274,280)	(1,246,932)	(963,908)
Capital contributions to Nora Gathering LLC			(6,400)
Tenant improvements		(4,053)	(12,212)
Proceeds from sale of available-for-sale securities	29,947	12,306	
Proceeds from sale of assets	619,999		
Investment in available-for-sale securities		(750)	(3,000)
Net cash used in investing activities	(624,334)	(1,239,429)	(985,520)
Cash flows from financing activities:			
Dividends paid	(131,625)	(127,292)	(115,368)
Proceeds from issuance of common stock		537,206	
Proceeds from issuance of long-term debt	750,000		700,000
Debt issuance costs and revolving credit facility origination fee	(11,738)	(10,962)	(6,874)
(Decrease) increase in short-term loans	(53,650)	48,650	(314,917)
Repayments and retirements of long-term debt	(15,457)		(4,300)
Proceeds and tax benefits from exercises under employee compensation plans	2,791	2,087	1,238
Net cash provided by financing activities	540,321	449,689	259,779
Net change in cash and cash equivalents	831,251		
Cash and cash equivalents at beginning of year			
Cash and cash equivalents at end of year	$ 831,251	$	$
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$ 130,719	$ 127,904	$ 107,475
Income taxes, net	$ 47,242	$ (129,495)	$ (120,074)

See notes to consolidated financial statements.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2011	2010
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 831,251	$
Accounts receivable (less accumulated provision for doubtful accounts: $16,371 in 2011; $18,335 in 2010)	153,321	156,709
Unbilled revenues	30,257	38,361
Inventory	123,960	137,853
Derivative instruments, at fair value	512,161	225,339
Assets held for sale		207,678
Prepaid expenses and other	39,184	62,000
Total current assets	1,690,134	827,940
Equity in nonconsolidated investments	136,972	191,265
Property, plant and equipment	8,768,713	7,689,025
Less: accumulated depreciation and depletion	1,962,404	1,778,934
Net property, plant and equipment	6,806,309	5,910,091
Investments, available-for-sale		28,968
Regulatory assets	94,095	100,949
Other	45,209	39,225
Total assets	$ 8,772,719	$ 7,098,438

See notes to consolidated financial statements.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2011	2010
	(Thousands)	
Liabilities and Common Stockholders Equity		
Current liabilities:		
Current portion of long-term debt	$ 219,315	$ 6,000
Short-term loans		53,650
Accounts payable	256,757	212,134
Derivative instruments, at fair value	123,306	106,721
Other current liabilities	205,532	218,479
Total current liabilities	804,910	596,984
Long-term debt	2,527,627	1,943,200
Deferred income taxes and investment tax credits	1,618,944	1,274,888
Unrecognized tax benefits	13,611	41,451
Pension and other post-retirement benefits	47,589	44,135
Other credits	166,208	119,084
Total liabilities	5,178,889	4,019,742
Common stockholders equity:		
Common stock, no par value, authorized 320,000 shares, shares issued: 175,684 in 2011 and 2010	1,734,994	1,723,898
Treasury stock, shares at cost: 26,207 in 2011 and 26,531 in 2010	(473,215)	(479,072)
Retained earnings	2,143,910	1,795,766
Accumulated other comprehensive income	188,141	38,104
Total common stockholders equity	3,593,830	3,078,696
Total liabilities and common stockholders equity	$ 8,772,719	$ 7,098,438

See notes to consolidated financial statements.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED COMMON STOCKHOLDERS EQUITY

YEARS ENDED DECEMBER 31, 2011, 2010 and 2009

	Common Stock			Accumulated Other	
	Shares Outstanding	No Par Value	Retained Earnings	Comprehensive (Loss) Income	Common Stockholders Equity
			(Thousands)		
Balance, December 31, 2008	130,866	$ 465,033	$ 1,653,797	$ (68,737)	$ 2,050,093
Comprehensive income (net of tax):					
Net income			156,929		156,929
Net change in cash flow hedges:					
Natural gas, net of tax of $27,166 (see Note 3)				44,401	44,401
Interest rate				115	115
Unrealized loss on available-for-sale securities				4,090	4,090
Pension and other post-retirement benefits liability adjustment, net of tax of $3,733				5,691	5,691
Total comprehensive income					211,226
Dividends ($0.88 per share)			(115,368)		(115,368)
Stock-based compensation plans, net	65	5,079			5,079
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 (see Note 3)				49,601	49,601
Interest rate				116	116
Unrealized gain 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
Total comprehensive income					280,244
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 (see Note 3)				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)
Total comprehensive income					629,806
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

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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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 equity 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.

Segments: Operating segments are revenue-producing components of the enterprise for which separate financial information is produced internally and 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 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. Until February 1, 2011, EQT Midstream also provided processing services. Distribution s operations primarily comprise the state-regulated distribution activities of the Company.

Substantially all of the Company s operating revenues, income from continuing 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 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 gains 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 and lower of cost or market review. Adjustments to reduce inventory to the lower of cost or market were not material for the years ended December 31, 2011, 2010 or 2009.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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

	December 31, 2011	December 31, 2010
	(Thousands)	
Oil and gas producing properties, successful efforts method	$ 5,772,083	$ 4,655,217
Accumulated depletion	1,177,526	967,473
Net oil and gas producing properties	4,594,557	3,687,744
Midstream plant	1,924,685	1,934,288
Accumulated depreciation and amortization	424,963	413,105
Net midstream plant	1,499,722	1,521,183
Distribution plant	980,793	976,394
Accumulated depreciation and amortization	325,836	328,781
Net distribution plant	654,957	647,613
Other properties, at cost less accumulated depreciation	57,073	53,551
Net property, plant and equipment	6,806,309	$ 5,910,091

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 $69.3 million, $56.8 million and $46.5 million in 2011, 2010 and 2009, respectively. The Company capitalized $13.3 million, $7.6 million and $0 of interest relative to Marcellus well development in 2011, 2010 and 2009, 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 total costs capitalized by the number of units expected to be produced over the life of the reserves. 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 $1.25 /Mcfe $1.26/Mcfe, and $1.06/Mcfe produced for the years ended December 31, 2011, 2010 and 2009, 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, 2011, 2010 and 2009, the Company did not recognize impairment charges on proved oil and gas properties.

Capitalized costs of unproved properties are evaluated at least annually for recoverability on an aggregated 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 $358.8 million and $445.9 million at December 31, 2011 and 2010, respectively. Unproved property impairments as a result of lease expirations prior to drilling of $2.6 million, $0.3 million, and $1.1 million are included in exploration expense for the years ended December 31, 2011, 2010 and 2009 respectively.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

The Company had capitalized exploratory well costs pending the determination of proved reserves of $6.9 million on an exploratory Utica well 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 to the Utica formation in 2010. At December 31, 2011 and 2010, the Company had no capitalized exploratory well costs. For additional information on oil and gas properties see Note 22 (unaudited).

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, 2011 and 2010 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. 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 and amortizes the deferral over subsequent periods in which billings either recover or repay such amounts. Such amounts are reflected on the Company s Consolidated Balance Sheets as other current assets or liabilities. For further information regarding regulatory assets, see Note 10.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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

	Years Ended December 31, 2011	2010	2009
		(Thousands)	
Distribution revenues	$ 380,960	$ 411,978	$ 507,481
Midstream revenues	125,872	124,958	112,778
Total regulated revenue	$ 506,832	$ 536,936	$ 620,259
Distribution purchased gas costs	$ 199,381	$ 231,407	$ 334,144
Midstream purchased gas costs	6,303	4,930	1,035
Total regulated purchased gas costs	$ 205,684	$ 236,337	$ 335,179
Distribution net revenue	$ 181,579	$ 180,571	$ 173,337
Midstream net revenue	119,569	120,028	111,743
Total regulated net revenue	$ 301,148	$ 300,599	$ 285,080
Distribution operating expenses	$ 100,205	$ 103,915	$ 100,567
Midstream operating expenses	69,944	65,029	66,355
Total regulated operating expenses	$ 170,149	$ 168,944	$ 166,922

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

	As of December 31, 2011	2010
	(Thousands)	
Distribution property, plant & equipment	$ 980,793	$ 976,394
Accumulated depreciation and amortization	325,836	328,781
Net Distribution property, plant & equipment	654,957	647,613
Midstream property, plant & equipment	604,867	701,936
Accumulated depreciation and amortization	137,339	160,269
Net Midstream property, plant & equipment	467,528	541,667
Total net regulated property, plant & equipment	$ 1,122,485	$ 1,189,280

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

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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 change 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 on its Statements of Consolidated Income as operating revenues.

Allowance for Funds Used During Construction: Carrying costs for the construction of certain long-term assets are capitalized by the Company and amortized over the related assets estimated useful lives. The capitalized amount for construction of regulated assets includes interest cost and a designated cost of equity for financing the construction of these assets which are subject to regulation by the 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 $ 2.2 million, $1.1 million and $0.4 million for the years ended December 31, 2011, 2010 and 2009, 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 $4.0 million, $0.3 million, and $1.2 million for the years ended December 31, 2011, 2010 and 2009, 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 $13.3 million, $8.2 million and $3.8 million during 2011, 2010, and 2009 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

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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: Included in other current liabilities in the Company s Consolidated Balance Sheets is approximately $85 million and $88 million of incentive compensation at December 31, 2011 and December 31, 2010, respectively.

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. 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

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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 percent 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 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 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 14.

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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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, 2011	2010
	(Thousands)	
Asset retirement obligation as of beginning of period	$ 66,315	$ 60,961
Accretion expense	5,032	4,633
Liabilities incurred	878	2,280
Liabilities settled	(1,316)	(1,559)
Revisions in estimated cash flows	33,851	
Asset retirement obligation as of end of period	$ 104,760	66,315

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 s. 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.

Recently Issued Accounting Standards:

Presentation of Comprehensive Income

In June 2011, the Financial Accounting Standards Board (FASB) issued a standard update intended to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income (OCI). In December 2011, the FASB provided some reporting relief, deferring the requirement to present reclassified items separately with their respective components of net income and OCI. The FASB upheld the requirement for companies to eliminate the presentation of OCI and its components in the statement of changes in stockholder s equity, instead requiring companies to present OCI in a single continuous statement or a two-statement approach. The amendments are effective for fiscal years beginning after December 15, 2011. The Company is currently evaluating the impact this standard will have on its financial statement disclosures.

Disclosures about Fair Value Measurements

In May 2011, the FASB issued a standard update intended to enhance the fair value disclosure requirements to result in common fair value measurement under United States generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). The amendments are to be applied prospectively, and are effective for annual periods beginning after December 15, 2011. The Company is currently evaluating the impact this standard will have on its financial statement disclosures.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

Disclosures about Offsetting Assets and Liabilities

In December 2011, the FASB issued a standard update intended to enhance disclosures required by requiring improved 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 amendments are to be applied prospectively and are 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. 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 and depreciation are billed to the operating segments based upon a fixed allocation of the headquarters annual operating budget. Differences between budget and actual headquarters expenses are not allocated to the operating segments.

The Company s management reviews and reports segment results for operating revenues and purchase gas costs with third party transportation costs reflected as a deduction from operating revenues. For the year ended December 31, 2011, because of increased materiality of these costs, the Company determined that consolidated results for these line items are required to be reported on a gross basis with third-party transportation costs recorded as a portion of purchased gas costs. The consolidated operating revenues, purchased gas costs and total operating expenses for all periods presented have been adjusted to reflect with this gross presentation. This adjustment had no impact on consolidated net income, consolidated operating income or on the segment results for any period presented. Management believes this presentation is not material to the overall financial statement presentation.

	Years Ended December 31,		
	2011	**2010**	**2009**
		(Thousands)	
Revenues from external customers:			
EQT Production	$ 791,285	$ 537,657	$ 420,990

EQT Midstream	525,345	580,698	465,444
Distribution	419,678	474,143	560,283
Less: intersegment and other revenues, net (a)	(96,374)	(218,103)	(135,361)
Total	$ 1,639,934	$ 1,374,395	$ 1,311,356
Operating income:			
EQT Production	$ 387,098	$ 223,487	$ 185,868
EQT Midstream (b)	416,611	178,866	154,197
Distribution	86,898	83,182	78,918
Unallocated expenses (c)	(29,288)	(15,056)	(62,192)
Total operating income	$ 861,319	$ 470,479	$ 356,791
Reconciliation of operating income to net income:			
Other income	34,138	12,898	8,585
Interest expense	136,328	128,157	111,779
Income taxes	279,360	127,520	96,668
Net income	$ 479,769	$ 227,700	$ 156,929

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

	As of December 31, 2011	As of December 31, 2010
	(Thousands)	
Segment assets:		
EQT Production	$ 5,256,645	$ 3,979,676
EQT Midstream	1,785,089	2,076,485
Distribution	850,414	848,419
Total operating segments	7,892,148	6,904,580
Headquarters assets, including cash and short-term investments	880,571	193,858
Total assets	$ 8,772,719	$ 7,098,438

	Years Ended December 31, 2011	2010	2009
		(Thousands)	
Depreciation, depletion and amortization:			
EQT Production	$ 257,144	$ 183,699	$ 117,424
EQT Midstream	57,135	61,863	53,291
Distribution	25,747	24,174	22,375
Other	(729)	549	2,988
Total	$ 339,297	$ 270,285	$ 196,078
Expenditures for segment assets:			
EQT Production (d)	$ 1,087,840	$ 1,245,914	$ 717,356
EQT Midstream	242,886	193,128	201,082
Distribution	31,313	36,619	33,707
Other	4,855	1,958	11,763
Total	$ 1,366,894	$ 1,477,619	$ 963,908

(a) Intersegment revenues primarily represent natural gas sales from EQT Production to EQT Midstream and transportation activities between EQT Midstream and Distribution. These activities were partly offset by the third-party transportation costs which were recorded in operating revenues and purchased gas costs at the consolidated level.

(b) EQT Midstream operating income for 2011 includes $202.9 million of gains on dispositions. See Note 5.

(c) Unallocated expenses consists primarily of incentive compensation and administrative costs that are not allocated to the operating segments.

(d) Expenditures for segment assets in the EQT Production segment include $57.2 million, $357.7 million and $31.0 million for undeveloped property acquisitions in 2011, 2010 and 2009, respectively. Expenditure 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 in 2011 and $230.7 million of undeveloped property which was acquired with EQT common stock in 2010.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

3. Derivative Instruments

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

The Company uses derivative commodity instruments that are 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 a fixed and variable price 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. Put option contracts provide protection from dropping prices and require the counterparty to pay the Company if the index price falls below the contract 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 short or long-term debt.

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 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 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. Over the counter (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.

A portion 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 has been designated and qualifies as cash flow hedges under Accounting Standards Codification Topic 815, Derivatives and Hedging. A portion 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 has been designated and qualifies as fair value hedges.

In addition, the Company enters into a limited amount of energy trading contracts to leverage its assets and limit its exposure to shifts in market prices. The Company also has a limited amount of other derivative instruments not designated as hedges. In 2008 and 2011, the Company effectively settled certain derivative commodity swaps and collars 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 Condensed 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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

	Years Ended December 31, 2011		2010 (Thousands)		2009	
Commodity derivatives designated as cash flow hedges						
Amount of gain recognized in other comprehensive income (OCI) (effective portion), net of tax	$	239,019	$	113,320	$	148,327
Amount of gain reclassified from accumulated OCI into operating revenues (effective portion), net of tax		72,179		63,719		103,926
Amount of (loss) gain recognized in operating revenues (ineffective portion) (a)		(181)		3,046		(2,068)
Interest rate derivatives designated as cash flow hedges						
Amount of loss recognized in OCI (effective portion), net of tax	$	(7,573)	$		$	
Amount of loss reclassified from accumulated OCI into interest expense (effective portion), net of tax		(140)		(116)		(115)
Amount of gain (loss) recognized in interest expense (ineffective portion) (a)						
Commodity derivatives designated as fair value hedges (b)						
Amount of gain recognized in operating revenues for fair value commodity contracts	$	12,263	$		$	
Fair value loss recognized in operating revenues for inventory designated as hedged item		(6,059)				
Derivatives not designated as hedging instruments:						
Amount of gain recognized in operating revenues	$	4,209	$	369	$	65

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

(b) 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, 2011		2010 (Thousands)	
Asset derivatives				
Commodity derivatives designated as hedging instruments	$	412,626	$	141,834
Commodity derivatives not designated as hedging instruments		99,535		83,505
Total asset derivatives	$	512,161	$	225,339
Liability derivatives				
Commodity derivatives designated as hedging instruments	$	3,681	$	12,097
Interest rate derivatives designated as hedging instruments		10,861		

Commodity derivatives not designated as hedging instruments		108,764		94,624
Total liability derivatives	$	123,306	$	106,721

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

In August 2011, the Company entered into a forward-starting interest rate swap to mitigate the risk of rising interest rates. The forward-starting interest rate swap was designated as a cash flow hedge of forecasted future interest payments. The Company recorded a deferred loss of $7.6 million in accumulated other comprehensive income, net of tax, as of December 31, 2011, associated with the change in fair value of the forward-starting interest rate swap. Additionally, the forward-starting interest rate swap is included in the liability derivatives designated as hedging instruments in the above table.

The net fair value of commodity derivative instruments changed during 2011 primarily as a result of the positive net fair value of derivatives executed in 2011 and a decrease in natural gas prices. The absolute quantities of the Company s derivative commodity instruments that have been designated and qualify as cash flow hedges totaled 349 Bcf and 181 Bcf as of December 31, 2011 and December 31, 2010, respectively, and are primarily related to natural gas swaps and collars.

The Company deferred net gains of $232.1 million and $65.2 million in accumulated other comprehensive income, net of tax, as of December 31, 2011 and 2010, 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 $150.8 million of net unrealized gains on its derivative commodity instruments reflected in accumulated other comprehensive income, net of tax, as of December 31, 2011 will be recognized in earnings during the next twelve months due to the settlement of hedged transactions.

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 limited 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, 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 current market conditions, counterparty credit spreads 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.

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, 2011 and 2010.

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 time to expiration of the related contract and are subject to change at the exchanges discretion. The Company recorded a current asset of $0.1 million as of December 31, 2011 and a current liability of $0.5 million as of December 31, 2010 for such deposits in its Consolidated Balance Sheets.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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, 2011, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $2.2 million, for which the Company had no collateral posted on December 31, 2011. If the Company s credit rating by S&P or Moody s had been downgraded below investment grade on December 31, 2011, the Company would have been required to post additional collateral of $2.2 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 unsecured medium-term debt was rated BBB by S&P and Baa2 by Moody s at December 31, 2011. 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.

4. Fair Value Measurements

The Company records its financial instruments, principally derivative instruments, at fair value in its Condensed 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, 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. 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, including the forward-starting interest rate swap, and assets in Level 3 include the Company s collar and option agreements and an insignificant portion 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 industry models that use significant observable inputs, including NYMEX and LIBOR forward curves and LIBOR-based discount rates. Swaps included in Level 3 are valued using internal models that use significant unobservable inputs; these internal models are validated each period with non-binding broker price quotes. Collars and options included in Level 3 are valued using internal models calculated with market derived volatilities. The Company uses NYMEX forward curves to value futures, commodity swaps, collars and options. The Company uses LIBOR forward curves to value interest rate swaps. The NYMEX and LIBOR forward curves are validated to external sources at least monthly.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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

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

Description	December 31, 2010	Fair value measurements at reporting date using: Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(Thousands)			
Assets				
Investments, available-for-sale	$ 28,968	$ 28,968	$	$
Derivative instruments, at fair value	225,339	8,968	99,489	116,882
Total assets	$ 254,307	$ 37,936	$ 99,489	$ 116,882
Liabilities				
Derivative instruments, at fair value	$ 106,721	$ 7,627	$ 98,884	$ 210
Total liabilities	$ 106,721	$ 7,627	$ 98,884	$ 210

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

	Fair value measurements using significant unobservable inputs (Level 3) Derivative instruments, at fair value, net Years ended December 31,	
	2011	**2010**
	(Thousands)	
Balance at January 1	$ 116,672	$ 88,570
Total gains or losses:		
Included in earnings	14	(14)
Included in other comprehensive income	81,825	87,330
Settlements	(55,251)	(59,214)
Transfers in and/or out of Level 3		
Balance at December 31	$ 143,260	$ 116,672
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities still held as of December 31	$	$ 5

The carrying value of cash equivalents and short-term loans approximates fair value due to the short maturity of the instruments.

The estimated fair value of long-term debt on the Consolidated Balance Sheets at December 31, 2011 and December 31, 2010 was approximately $3.0 billion and $2.0 billion respectively. The fair value was estimated using the Company s established fair value methodology based on quoted rates reflective of the remaining maturity.

For information on the fair value of the defined benefit pension plan assets see Note 13.

5. Sale of Properties

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. As of December 31, 2010, EQT classified the Langley properties as assets held for sale in the accompanying Consolidated Balance Sheets.

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 fourth quarter of 2011, the Company sold leases relating to 1,919 gross acres in Lycoming County, Pennsylvania for $6.0 million and realized a pre-tax gain of $ 3.9 million.

6. 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

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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. The notes had a fair value of $64.2 million.

Under U.S. 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 is included in other income 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.

During 2010, the Company acquired approximately 58,000 net acres in the Marcellus from a group of private operators and landowners. The acreage is located primarily in Cameron, Clearfield, Elk and Jefferson counties in Pennsylvania. The purchase included a 200 mile gathering system, with associated rights of way, and approximately 100 producing vertical wells. The Company paid $282.2 million for these assets, $230.7 million in EQT stock and $51.5 million in cash.

7. Income Taxes

Income tax expense (benefit) is summarized as follows:

	Years Ended December 31, 2011	2010 (Thousands)	2009
Current:			
Federal	$ 39,867	$ (25,377)	$ (134,763)
State	6,076	(388)	(2,712)
Subtotal	$ 45,943	(25,765)	(137,475)
Deferred:			
Federal	$ 202,392	132,161	223,177
State	31,627	21,751	11,599
Subtotal	$ 234,019	153,912	234,776
Amortization of deferred investment tax credit	(602)	(627)	(633)
Total	$ 279,360	$ 127,520	$ 96,668

The current tax expense recorded in 2011 primarily related to alternative minimum tax 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 and 2009 primarily related to additional cash refunds received related to the 2009 and 2008 tax net operating loss carrybacks.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (2010 Tax Relief Act) extended the research and experimentation (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. EQT also received a refund of $115.2 million in 2009, relating to a 2008 net operating loss carryback. The Company generated net operating losses for federal tax purposes from 2008 to 2011, 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 84% of drilling costs as IDCs in the year incurred. The Company expects to pay minimal federal income taxes for the next few years as the Company s drilling program in Appalachia continues to generate tax losses.

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

	Years Ended December 31,		
	2011	2010	2009
		(Thousands)	
Tax at statutory rate	$ 265,695	$ 124,327	$ 88,759
State income taxes	25,416	14,585	8,681
Incentive or deferred compensation			8,925
Federal tax credits and incentives	(660)	(600)	1,613
Regulatory basis differences	(1,251)	(2,713)	(9,336)
Permanent basis differences	(2,411)	(1,258)	(3,025)
Other	(7,429)	(6,821)	1,051
Income tax expense	$ 279,360	$ 127,520	$ 96,668
Effective tax rate	36.8%	35.9%	38.1%

The Company received consent in 2009 from the Internal Revenue Service (IRS) for a change in accounting method that allows current income tax deductions for certain repair costs that are capitalized for book purposes. The Company s regulated business accounts for these tax deductible repair costs as a permanent difference, which reduce the effective tax rate in the year of deduction, because the related deferred taxes are recoverable in rates.

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.

The Company s effective tax rate for its continuing operations for the year ended December 31, 2010 was 35.9% compared to 38.1% for the year ended December 31, 2009. The higher tax rate in 2009 was primarily the result of the impact in 2009 of certain nondeductible expenses and the loss of certain prior year deductions as a result of carrying 2009 losses back to receive a cash refund of taxes paid. These higher rates in 2009 were partially mitigated by the regulatory asset for repairs costs capitalized for financial accounting purposes. Rates were also lower in 2010 due to the reduction of the reserve for uncertain tax positions as a result of the lapse of applicable statutes of limitation.

Section 162(m) of the Internal Revenue Code disallows, with certain exceptions such as performance based compensation paid pursuant to a shareholder approved plan, a federal income tax deduction for annual compensation over $1 million paid to any covered employee. The covered employees are the principal executive officer and the three most highly-compensated officers other than the principal executive officer and the principal financial officer.

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

During 2009, payments awarded under the 2009 Shareholder Value Plan were subject to this limitation which resulted in $8.9 million of tax expense. The establishment of the regulatory asset for the accounting method change on repairs costs resulted in a decrease in tax expense of $9.8 million in 2009.

In December 2011, the 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):

	2011	2010	2009
		(Thousands)	
Balance at January 1	$37,943	$ 40,726	$ 34,171
Additions based on tax positions related to current year	1,245	2,524	10,622
Additions for tax positions of prior years	184	3,391	672
Reductions for tax positions of prior years	(7,886)	(4,618)	(1,550)
Settlements	-		
Lapse of statute of limitations	(756)	(4,080)	(3,189)
Balance at December 31	$ 30,730	$ 37,943	$ 40,726

Included in the tabular reconciliation above at December 31, 2011, 2010 and 2009 are $15.9 million, $21.2 million and $29.5 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 $19.4 million and $8.5 million for the periods ending December 31, 2011 and 2010, respectively, are recorded in the Consolidated Balance Sheets as a reduction of the deferred tax asset for net operating loss 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 $9.7 million and $3.9 million of previously recorded interest expense in 2011 and 2010, respectively, and recognized approximately $2.5 million of interest expense for the year ended December 31, 2009. Interest and penalty of $2.3 million, $12.0 million and $15.9 million was included in the balance sheet reserve at December 31, 2011, 2010 and 2009, respectively.

The total amount of unrecognized tax benefits, inclusive of interest and penalties, was $33.0 million, $49.9 million and $56.6 million as of December 31, 2011, 2010 and 2009, respectively. The total amount of unrecognized tax benefits (excluding interest and penalties) that, if recognized, would affect the effective tax rate was $5.2 million, $8.9 million and $8.9 million as of December 31, 2011, 2010 and 2009, respectively.

As of December 31, 2011, it was reasonably possible that the total amount of unrecognized tax benefits could decrease by up to $18.0 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 2011. Because the Company is in a net operating loss position, the Company did not create unrecognized tax benefits for certain tax positions in 2011 and 2010; such amounts instead reduce the net operating loss carryforward for those periods. Decreases to the unrecognized tax benefit balance during 2011 and 2010 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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

During the second quarter of 2011, the Company finalized a settlement with the IRS relating to research and experimentation tax credits claimed from 2001 to 2005. Except for claims related to tax losses for those years, the consolidated federal income tax liability of the Company has been settled with the IRS through 2005. The Company is currently under audit for the 2006 to 2009 periods. The examination of these periods began in the second quarter of 2010. 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,	
	2011	**2010**
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets	$(449,888)	$ (385,948)
Total deferred income tax liabilities	2,038,225	1,622,520
Total net deferred income tax liabilities	1,588,337	1,236,572
Total deferred income tax liabilities (assets)		
Tax depreciation in excess of book depreciation	1,037,691	918,567
Drilling and development costs expensed for income tax reporting	836,219	632,985
Accumulated other comprehensive income	120,295	21,217
Regulatory temporary differences	43,005	44,335
Deferred purchased gas cost	1,015	5,113
Financial instruments	(1,303)	302
Incentive compensation	(1,324)	(15,971)
Investment tax credit	(1,467)	(1,856)
Uncollectible accounts	(3,953)	(4,092)
Post-retirement benefits	(8,140)	(6,630)
Deferred compensation plans	(10,814)	(15,698)
Alternative minimum tax credit carryforward	(65,509)	(26,017)
Net operating loss carryforwards	(337,921)	(305,787)
Other	(19,457)	(9,896)
Total (including amounts classified as current (assets) of ($26,867) and ($33,586), respectively)	$1,588,337	$1,236,572

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 net deferred tax liability relating to the Company s accumulated other comprehensive loss balance as of December 31, 2010 was comprised of a $39.6 million deferred tax liability related to the Company s net unrealized gain from hedging transactions, a $2.6 million deferred tax liability related to the unrealized gain on available-for-sale securities, a $7.0 million deferred tax asset related to other post-retirement benefits and a $14.0 million deferred tax asset related to the Company s pension plans.

The Company also has a total deferred tax asset of $278.8 million related to the federal net operating loss carryforward created in 2011, 2010 and 2008 of $54.9 million, $229.2 million and $2.2 million, respectively. The deferred tax asset has been reduced for uncertain tax positions of approximately $7.5 million and $0.8 million as of December 31, 2011 and 2010, respectively. The federal net operating loss carryforward period is 20 years and, if unused, the loss carryforward for 2008, 2010 and 2011 will expire in 2028, 2030 and 2031, respectively.

The Company is subject to the alternative minimum tax (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 $65.5 million. Since AMT taxes paid can be credited against

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

regular tax and have an indefinite carryforward period, this item is reflected as a deferred tax asset on the Company s balance sheet.

As of December 31, 2011, the Company has recorded a deferred tax asset of $59.1 million, which is 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. As of December 31, 2010, the Company had recorded a deferred tax asset of $52.2 million, which is net of valuation allowances of $3.3 million, related to tax benefits from state net operating loss carryforwards with various expiration dates ranging from 2011 to 2030. The deferred tax asset has been reduced for uncertain tax positions of approximately $8.8 million and $5.7 million as of December 31, 2011 and 2010, respectively.

During the years ended December 31, 2011 and 2010, share-based payment arrangements paid in stock generated a $6.6 million and $5.0 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. An income tax benefit of approximately $1 million for the year ended December 31, 2009 triggered by the exercise of nonqualified employee stock options and vesting of restricted share awards is reflected as an addition to common stockholders equity.

8. 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 equity in the nonconsolidated investments:

Investees	**Location**	**Interest Type**	**Ownership as of December 31, 2011**	**December 31, 2011**	**December 31, 2010**
				(Thousands)	
Nora Gathering, LLC (Nora LLC)	USA	Joint	50%	$ 136,972	$ 153,345
Appalachian Natural Gas Trust (ANGT)	USA		100%		37,920
Total equity in nonconsolidated investments				$ 136,972	$ 191,265

The Company s ownership share of the earnings for 2011, 2010 and 2009 related to the total investments accounted for under the equity method was $7.2 million, $9.7 million, and $6.5 million, respectively.

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 2010 or 2011. EQT Midstream s investment in Nora LLC totaled $137.0 million and $153.3 million as of December 31, 2011 and 2010, respectively.

Prior to May 4, 2011, EQT Production had a limited 1% Class B equity investment in ANGT which represented a profits interest in natural gas producing properties located in the Appalachian Basin region of the United States. Effective May 4, 2011, the Company, through EQT Production Company, acquired the Class A interest in ANGT thereby acquiring 100% of the net profits interest associated with the producing properties (the ANPI transaction). As a result of this transaction, the Company removed the equity investment in the trust from its books. See Note 6 for further details.

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

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

Summarized Balance Sheets

	As of December 31, 2011	As of December 31, 2010
	(Thousands)	
Current assets	$ 18,838	$ 45,493
Noncurrent assets	260,286	399,447
Total assets	$ 279,124	$ 444,940
Current liabilities	$ 5,210	$ 8,013
Stockholders equity	273,914	436,927
Total liabilities and stockholders equity	$ 279,124	$ 444,940

Summarized Statements of Income

	Years Ended December 31, 2011	2010	2009
		(Thousands)	
Revenues	$ 49,772	$ 62,618	$ 89,980
Operating expenses	35,520	41,693	63,877
Net income	$ 14,252	$ 20,925	$ 26,103

9. Investments, Available-For-Sale

As of December 31, 2010 the investments classified by the Company as available-for-sale consisted of $29.0 million in equity and bond funds intended to fund plugging and abandonment and other liabilities for which the Company self-insures. As of December 31, 2011, all investments were liquidated.

	December 31, 2010 Adjusted Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(Thousands)		
Equity funds	$ 19,862	$ 7,362	$	$ 27,224

Bond funds		1,574		170				1,744
Total investments	$	21,436	$	7,532	$		$	28,968

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.

There were no investment purchases during 2011. During 2010, the Company purchased additional securities with a cost basis totaling $ 0.8 million.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

10. Regulatory Assets

The following table summarizes the Company s regulatory assets, net of amortization, as of December 31, 2011 and 2010. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of its regulatory assets.

Description	**December 31, 2011**	**2010**
	(Thousands)	
Deferred taxes	$ 89,224	$ 91,004
Deferred purchased gas costs	3,132	12,466
Other post-retirement benefits other than pensions	4,168	7,327
Other recoverable costs	703	3,862
Total regulatory assets	97,227	114,659
Amounts classified as other current assets	3,132	13,710
Total long-term regulatory assets	$ 94,095	$100,949

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 amortized $0.7 million and $1.4 million for the years ended December 31, 2010 and 2009, respectively, for post-retirement benefits other than pensions which had been previously deferred. 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 pension is expected to be recovered in rates within approximately 6 years.

As of December 31, 2011 the Company also had a regulatory liability of $2.1 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.

11. Short-Term Loans

On December 8, 2010, the Company entered into a $1.5 billion four-year revolving credit agreement, which replaced the Company s previous $1.5 billion five-year revolving credit agreement. The Company may request two one-year extensions of the December 8, 2014 stated maturity date; however, these extensions require the approval of greater than 50% of the lenders underwriting the credit facility. Any such extension shall only apply to the lenders who consent to the extension and any lender who replaces a non-consenting lender pursuant to the terms of the credit agreement. The revolving credit agreement may be used for working capital, capital expenditures, share repurchases and other purposes including support of a commercial paper program. 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 of 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 20 financial institutions each of which is obligated to fund its pro-rata portion of any borrowings by the Company.

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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

As of December 31, 2011, the Company had no loans or letters of credit outstanding under the revolving credit facility. As of December 31, 2010, the Company had loans of $53.7 million and an irrevocable standby letter of credit of $23.5 million outstanding under the revolving credit facility. For the years ended December 31, 2011 and 2010, the Company paid commitment fees averaging approximately 30 basis points and 10 basis points, respectively, to maintain credit availability under the revolving credit facility.

The weighted average interest rate for short-term loans outstanding as of December 31, 2010 was 1.8%. The maximum amount of outstanding short-term loans at any time during the year was $104.0 million in 2011 and $139.7 million in 2010. The average daily balance of short-term loans outstanding over the course of the year was approximately $5.5 million and $24.9 million at weighted average annual interest rates of 1.81% and 0.70% during 2011 and 2010, respectively.

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 leverage 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 s financial covenants 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, 2011, the Company is in compliance with all existing debt covenants.

12. Long-Term Debt

	December 31, 2011	December 31, 2010
	(Thousands)	
7.76% notes, due 2012 thru 2016	$ 53,742	$ -
5.15% notes, due November 15, 2012	200,000	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	-
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	46,200
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
	2,746,942	1,949,200
Less debt payable within one year	219,315	6,000
Total long-term debt	2,527,627	$ 1,943,200

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 Company has recorded a premium on this debt of $ 6.1 million as of December 31, 2011.

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 Company s debt rating would not trigger a default under the indentures and other agreements governing the Company s indebtedness.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

Aggregate maturities of long-term debt are $219.3 million in 2012, $23.2 million in 2013, $11.2 million in 2014, $166.0 million in 2015 and $2.9 million in 2016.

13. Pension and Other Post-retirement Benefit Plans

The following table sets forth the defined benefit pension and other post-retirement benefit plans funded status and amounts recognized for those plans in the Company s Consolidated Balance Sheets:

	For the Years Ended December 31,			
	2011	**2010**	**2011**	**2010**
	Pension Benefits		**Other Benefits**	
	(Thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 61,452	$ 63,801	$ 34,706	$ 37,423
Service cost	500	600	620	616
Interest cost	3,115	3,390	1,771	1,974
Actuarial loss (gain)	3,842	1,545	1,602	(898)
Benefits paid	(5,776)	(6,053)	(3,406)	(4,409)
Expenses paid	(440)	(599)	-	
Settlements	(808)	(1,236)	-	
Special termination benefits	-	4	-	
Benefit obligation at end of year	$ 61,885	$ 61,452	$ 35,293	$ 34,706
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 48,083	$ 48,998	-	$
Actual gain on plan assets	599	5,719	-	
Contributions	4,293	1,254	$ 19	
Benefits paid	(5,776)	(6,053)	-	
Expenses paid	(440)	(599)	-	
Settlements	(808)	(1,236)	-	
Fair value of plan assets at end of year	$ 45,951	$ 48,083	$ 19	$
Funded status at end of year	$ (15,934)	$ (13,369)	$ (35,274)	$ (34,706)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$ -	$ (2)	$ (3,619)	$ (3,938)
Noncurrent liabilities	$ (15,934)	(13,367)	(31,655)	(30,768)
Net amount recognized	$ (15,934)	$ (13,369)	$ (35,274)	$ (34,706)

Amounts recognized in accumulated other comprehensive income, net of tax, consist of:								
Net loss	$	24,373	$	20,995	$	13,797	$	13,616
Net prior service (credit)		-				(1,890)		(2,805)
Net amount recognized	$	24,373	$	20,995	$	11,907	$	10,811

The accumulated benefit obligation for all defined benefit pension plans was $61.9 million and $61.5 million at December 31, 2011 and 2010, respectively. The Company uses a December 31 measurement date for its defined benefit pension and other post-retirement plans.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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,					
	2011	2010	2009	2011	2010	2009
	Pension Benefits			Other Benefits		
	(Thousands)					
Components of net periodic benefit cost:						
Service cost	$ 500	$ 600	$ 435	$ 620	$ 616	$ 575
Interest cost	3,115	3,390	3,624	$ 1,771	1,974	2,148
Expected return on plan assets	(4,070)	(4,289)	(4,578)	-		
Amortization of prior service cost	-		16	$ (902)	(902)	(902)
Recognized net actuarial loss	1,471	1,323	1,191	$ 1,605	1,652	1,797
Settlement loss and special termination benefits	530	569	838	-		
Curtailment loss	-		39	-		
Net periodic benefit cost	$ 1,546	$ 1,593	$ 1,565	$ 3,094	$ 3,340	$ 3,618

Under the 2006 Equitrans rate case settlement, the Company amortized post-retirement benefits other than pensions previously deferred over a five-year period. Currently, the Company recognizes expenses 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 and $1.4 million, respectively, for the years ended December 31, 2010 and 2009. The previously deferred amounts were fully amortized in 2010.

	For the Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	Pension Benefits			Other Benefits		
	(Thousands)					
Other changes in plan assets and benefit obligations recognized in other comprehensive income, net of tax:						
Net (gain) loss	$3,378	$ (1,056)	$ (4,006)	$ 181	$ (1,246)	$ (2,124)
Net prior service (credit) cost			(33)	915	281	472
Total recognized in other comprehensive income, net of tax	$3,378	(1,056)	(4,039)	$ 1,096	(965)	(1,652)
Total recognized in net periodic benefit cost and other comprehensive income, net of tax	$4,924	$ 537	$ (2,474)	$ 4,190	$ 2,375	$ 1,966

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 over the next fiscal year is $1.1 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 over the next fiscal year are $0.9 million and $(0.5) million.

88

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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,			
	2011	2010	2011	2010
	Pension Benefits		Other Benefits	
Discount rate	4.25%	5.50%	4.25%	5.50%
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,			
	2011	2010	2011	2010
	Pension Benefits		Other Benefits	
Discount rate	5.50%	5.75%	5.50%	5.75%
Expected return on plan assets	8.00%	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, 2012 is 7.75%. This assumption will be used to derive the Company s 2012 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 is 8.00% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.00% in 2018.

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

	One-Percentage-Point Increase			One-Percentage-Point Decrease		
	2011	2010	2009	2011	2010	2009
		Pension Benefits			Other Benefits	
			(Thousands)			
Increase (decrease) to total of service and interest cost components	$ 40	$ 47	$ 52	$ (39)	$ (46)	$ (51)
Increase (decrease) to post-retirement benefit obligation	$ 730	$ 756	$ 836	$ (702)	$ (723)	$ (795)

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

The Company s pension asset allocation at December 31, 2011 and 2010 and target allocation for 2012 by asset category are as follows:

Asset Category	Target Allocation 2012	Percentage of Plan Assets at December 31, 2011	2010
Domestic broadly diversified equity securities	40% - 60%	48%	46%
Fixed income securities and inflation hedge securities	20% - 60%	39%	34%
International broadly diversified equity securities	5% - 15%	9%	14%
Other	0% - 15%	4%	6%
		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 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 $4.3 million, $1.3 million and $11.6 million to its pension plan during 2011, 2010 and 2009, respectively to meet certain funding targets. The Company expects to make cash payments of at least $3.6 million related to its pensions during 2012, which will meet the 80% funding obligation on its 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 of the Company.

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: $6.4 million in 2012; $6.1 million in 2013; $6.2 million in 2014; $5.5 million in 2015; $5.3 million in 2016; and $23.4 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: $3.7 million in 2012; $3.7 million in 2013; $3.6 million in 2014; and $3.4 million in 2015; $3.4 million in 2016; and $14.8 million in the five years thereafter.

Expense recognized by the Company related to its 401(k) employee savings plans totaled $10.1 million in 2011, $10.4 million in 2010 and $10.1 million in 2009.

The Company reports 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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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.

Investments in the plan assets include mutual funds with a fair value of $20.0 million and $19.1 million as of December 31, 2011 and 2010, respectively. These investments are based upon daily unadjusted quoted prices and therefore are considered Level 1.

Investments in the plan assets include common/collective trusts with a fair value of $25.9 million and $29.0 million as of December 31, 2011 and 2010, respectively. These investments are valued at current market value of the underlying assets of the fund and therefore are considered Level 2.

As of December 31, 2011 and 2010, the plan does not hold any assets whose fair value is determined using unobservable inputs and therefore would be considered Level 3.

14. Common Stock and Earnings Per Share

At December 31, 2011, shares of EQT s authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	6,233
Total	26,690

Earnings Per Share

The computation of basic and diluted earnings per common share is shown in the table below:

	Years Ended December 31, 2011	2010	2009
	(Thousands except per share amounts)		
Basic earnings per common share:			
Net income	$ 479,769	$ 227,700	$ 156,929
Average common shares outstanding	149,392	144,458	130,820
Basic earnings per common share	$ 3.21	$ 1.58	$ 1.20
Diluted earnings per common share:			
Net income	$479,769	$ 227,700	$ 156,929
Average common shares outstanding	149,392	144,458	130,820
Potentially dilutive securities:			
Stock options and awards (a)	817	774	662
Total	150,209	145,232	131,482
Diluted earnings per common share	$ 3.19	$ 1.57	$ 1.19

(a) Options to purchase 6,480, 1,229,109 and 955,107 shares of common stock were not included in the computation of diluted earnings per common share for 2011, 2010 and 2009, respectively, because the options exercise prices were greater than the average market prices of the common shares in the applicable year.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

15. Accumulated Other Comprehensive Income

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

	December 31, 2011	December 31, 2010
	(Thousands)	
Net unrealized gain from natural gas hedging transactions	$ 232,066	$ 65,226
Net unrealized loss from interest rate swaps	(7,645)	(212)
Unrealized gain on available-for-sale securities		4,896
Pension and other post-retirement benefits liability adjustment	(36,280)	(31,806)
Accumulated other comprehensive income	$ 188,141	$ 38,104

16. Share-Based Compensation Plans

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

	Years Ended December 31, 2011	2010	2009
		(Thousands)	
2008 Executive Performance Incentive Program	923	316	770
2010 Executive Performance Incentive Programs	2,118	2,905	
2009 Shareholder Value Plan			45,097
2007 Supply Long-Term Incentive Program	198	6,763	8,652
2010 Stock Incentive Award Program	4,241	4,134	
2011 Value Driver Award Program	15,807		
2011 Volume and Efficiency Program	5,384		
Restricted stock awards	2,281	3,020	3,634
Non-qualified stock options	6,057	4,045	3,134
Non-employee directors share-based awards	3,320	1,196	557
Total share-based compensation expense	40,329	$ 22,379	$ 61,844

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 2.

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2011, 2010 and 2009, was $3.1 million, $2.2 million and $0.8 million, respectively. During the years ended December 31, 2011 and 2010 share-based payment arrangements paid in stock generated tax benefit of $8.1 million and $6.0 million, respectively. As a result of the Company s net operating loss position, excess tax benefits of $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. The actual tax benefits realized for tax deductions, including excess tax benefits, from share-based payment arrangements which were paid in stock for the year ended December 31, 2009 was $2.2 million. 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 IRC as discussed in Note 7.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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 Co.
Chesapeake Energy Corp.	National Fuel Gas Co.	Southwestern Energy Co.
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 Plan (2010 Program) under the 2009 Long-Term Incentive Plan. The 2010 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 161,940 units were granted and no additional units may be granted. The vesting of the units under the 2010 Program 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 over the period January 1, 2010 through December 31, 2012 and the level of production sales revenues over the period January 1, 2010 through September 30, 2012. If earned, the 2010 Program units are expected to be distributed in Company common stock. 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 period. 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%.

The peer companies for the 2010 Program are 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 Co.	Southern Union Co.
El Paso Corp.	ONEOK, Inc.	Southwestern Energy Co.
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.

2009 Shareholder Value Plan

In December 2008, the Compensation Committee of the Board of Directors adopted the 2009 Shareholder Value Plan (SVP) under the 1999 Long-Term Incentive Plan. The SVP was established to ensure continued alignment with shareholders, to recognize the Company s evolution from a diversified utility to an integrated energy company and to continue to encourage sustained high performance and shareholder return. The effective date of the SVP was

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

January 1, 2009. The vesting of the stock units granted under the 2009 SVP occurred on December 31, 2009, after the ordinary close of the performance period. The vesting resulted in approximately 2.2 million units (225% of the award) with a value of approximately $45 million being distributed in cash on December 31, 2009. 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.

2007 Supply Long-Term Incentive Program

Effective July 1, 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 earned were increased to a maximum of 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

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. A total of 155,850 target performance awards were initially granted under the 2010 SIA. The vesting of the awards under the 2010 SIA will occur on the third anniversary of the grant date. The payout opportunity with respect to the target performance awards was contingent upon adjusted 2010 earnings before interest, taxes, depreciation and amortization (EBITDA) performance as compared to the Company s annual business plan and individual, business unit and Company value driver performance over the period January 1, 2010 through December 31, 2010. Adjusting for the performance multiplier and forfeitures, as of December 31, 2011 there were 295,635 confirmed performance awards outstanding under the 2010 SIA which are expected to be distributed in Company common stock.

2011 Value Driver Award Program

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 awarded vested upon payment following the first anniversary of the grant date; the remaining 50% of the units awarded will vest upon the payment date following the second anniversary of the grant date. The payment varied between zero and 300% of the number of units granted contingent upon adjusted 2011 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, 2011 through December 31, 2011. As of December 31, 2011, 523,347 confirmed awards were outstanding under the 2011 VDA. Half of the awards were distributed in cash in February 2012. The remainder of the awards is expected to vest and be paid in cash in the first quarter of 2013. The Company accounts 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 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. Total liability recorded for the 2011 VDA was $24.1 million for the year ended December 31, 2011, which included $8.3 million of cost capitalized and $15.8 million recorded as expense in the Company s Consolidated Statements of Income.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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. A total of 260,330 awards were granted under the 2011 VEP. The payout opportunity with respect to the target awards will range from zero to three times 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. The total liability recorded for the 2011 VEP was $7.3 million for the year ended December 31, 2011, which included $1.9 million of cost capitalized and $5.4 million recorded as expense in the Company s Consolidated Statements of Income.

Restricted Stock Awards

The Company granted 65,390, 85,720 and 62,340 restricted stock awards during the years ended December 31, 2011, 2010 and 2009, respectively, to key employees of the Company. The majority of the shares granted will be fully vested at the end of the three-year period commencing with the date of grant. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Company s stock, was approximately $52, $43 and $33 for the years ended December 31, 2011, 2010 and 2009, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2011, 2010 and 2009 was $5.1 million, $2.9 million and $6.0 million, respectively.

As of December 31, 2011, there was $3.8 million of total unrecognized compensation cost related to nonvested restricted stock awards. That cost is expected to be recognized over a remaining weighted average vesting term of approximately 15 months.

A summary of restricted stock activity as of December 31, 2011, 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, 2011	231,900	$ 45.22	$ 10,486,005
Granted	65,390	$ 51.50	3,367,478

Vested	(93,070)	$ 54.78	(5,098,498)
Forfeited	(23,270)	$ 41.12	(956,791)
Outstanding at December 31, 2011	180,950	$ 43.10	$ 7,798,194

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, 2011, 2010 and 2009. 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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

	Years Ended December 31,		
	2011	**2010**	**2009**
Risk-free interest rate	2.02%	1.60% - 2.50%	N/A
Dividend yield	2.19%	2.10% - 2.34%	N/A
Volatility factor	.29	.28	N/A
Expected term	5 years	5 years	N/A

The Company granted 229,100 and 409,100 stock options during the years ended December 31, 2011 and 2010, respectively. The weighted average grant date fair value of the options was $10.06 and $9.31 for the years ended December 31, 2011 and 2010, respectively. The total intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009 was $18.3 million, $7.5 million and $1.6 million, respectively. No options were granted in 2009.

As of December 31, 2011, there was $2.1 million of total unrecognized compensation cost related to outstanding nonvested stock options which will be recognized over the next 1.5 years.

A summary of option activity as of December 31, 2011, 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, 2011	2,282,276	$ 34.31		
Granted	229,100	$ 44.84		
Exercised	(561,655)	$ 17.05		
Forfeited	(2,934)	$ 49.17		
Outstanding at December 31, 2011	1,946,787	$ 40.51	5.3 years	$ 28,154,700
Exercisable at December 31, 2011	1,710,762	$ 40.10	2.9 years	$ 25,445,034

Non-employee Directors Share-Based Awards

The Company has also 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 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 150,423 non-employee director share based awards were outstanding as of December 31, 2011. A total of 22,140, 28,348 and 23,760 share based awards were granted to non-employee directors during the years ended December 31, 2011, 2010 and 2009, respectively. The weighted average fair value of these grants, based on the grant date fair value of the Company s stock, was $44.84, $38.74 and $41.68 for the years ended December 31, 2011, 2010 and 2009, respectively.

2012 Value Driver Award Program and 2012 Executive Performance Incentive Plan

Effective 2012, the Compensation Committee of the Board of Directors adopted the 2012 Value Driver Award Program (2012 VDA) and the 2012 Executive Performance Incentive Program (2012 EPIP) under the 2009 Long-Term Incentive Plan. The 2012 VDA and 2012 EPIP were established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

A total of 265,230 units were granted under the 2012 VDA. Fifty percent of the units awarded under the 2012 VDA will vest upon the payment date following the first anniversary of the grant date; the remaining 50% of the units awarded under the 2012 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 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. If earned, the 2012 VDA units are expected to be paid in stock. The Company has not recorded any obligation or expense related to 2012 VDA as of December 31, 2011.

A total of 377,440 units were granted under the 2012 EPIP. The vesting of the units under the 2012 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, 2012 through December 31, 2014. If earned, the 2012 Program units are expected to be distributed in Company common stock. The Company has not recorded any obligation or expense related to 2012 EPIP as of December 31, 2011.

2012 Stock Options

Effective January 1, 2012, the Compensation Committee of the Board of Directors granted of non-qualified stock options to key employees of the Company. The 2012 options are ten-year options, with an exercise price of $54.79, and a vesting schedule as follows: 50% on January 1, 2013 and 50% on January 1, 2014, contingent upon continued employment with the Company on such dates. The Company has not recorded any obligation or expense related to 2012 Stock Options as of December 31, 2011.

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 customer accounted for more than 10% of revenues in 2011, 2010 or 2009.

Approximately 66% of the Company s accounts receivable balance as of December 31, 2011 and 2010, 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, 2011, 2010 or 2009.

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, institutional 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 276,500 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 collections 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

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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 analysis to monitor and evaluate its credit risk exposure to financial counter-parties. This includes monitoring market conditions, counterparty credit spreads 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, 2011, the Company is not in default under any derivative contracts and has no knowledge of default by any other counterparty to derivative contracts. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

As of December 31, 2011, approximately 11% of the Company s workforce was subject to collective bargaining agreements. The collective bargaining agreement which covers approximately 9% of the Company s workforce expired on September 25, 2011. The union agreed to continue working under the terms and conditions of the expired labor agreement while the parties continue negotiations for a new agreement. The collective bargaining agreement which covers approximately 1% of the Company s workforce will expire on May 21, 2012.

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, 2011 totaled $2,331.4 million (2012 - $192.2 million, 2013 - $165.2 million, 2014 - $148.3 million, 2015 - $178.7 million, 2016 - $173.7 million and thereafter - $1,473.3). The Company believes that a portion of these demand charges are recoverable in customer rates as follows: approximately $17.6 million in 2012, $3.5 million in 2013, $3.5 million in 2014, $3.5 million in 2015, and $0.9 million in 2016. The Company has entered into agreements to release some of its capacity to various third parties. Amounts included above for capacity released under long-term agreements approximate $61.8 million, $47.5 million and $20.4 million in 2012, 2013 and 2014, respectively.

The Company has agreements with drilling contractors to provide drilling equipment and services to the Company. These obligations totaled approximately $90.2 million as of December 31, 2011. Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $76.9 million in 2011, $97.4 million in 2010 and $62.3 million in 2009. Future lease payments under non-cancelable operating leases as of December 31, 2011 totaled $200.3 million (2012 - $39.9 million, 2013 - $38.7 million, 2014 - $28.7 million, 2015 - $18.3 million, 2016 - $7.9 million and thereafter - $66.8 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 $30.2 million as of December 31, 2011 (2012 - $2.1 million, 2013 - $2.1 million, 2014 - $2.2 million, 2015 - $2.2 million, 2016 - $2.2 million and thereafter - $19.4 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

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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 $1.7 million is included in other credits in the Consolidated Balance Sheets as of December 31, 2011.

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 is approximately $213 million as of December 31, 2011, extending at a decreasing amount for approximately 16 years. In addition, the Company agreed to maintain in place certain outstanding payment and performance bonds, letters of credit and other guarantee obligations supporting NORESCO s obligations under certain customer contracts, existing leases and other items with an undiscounted maximum exposure to the Company as of December 31, 2011 of approximately $35 million, of which approximately $34 million relates to bonds that were to have been terminated as of December 31, 2010 for work completed under the underlying contracts. The Company is working with NORESCO to resolve any open matters with respect to these bonds.

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. Office Consolidation / Impairment Charges

In the third quarter of 2009, the Company completed the relocation of its corporate headquarters and other operations to downtown Pittsburgh. As a result of the relocation, the Company recorded an impairment charge of $5.2 million in selling, general and administrative expense in the Statements of Consolidated Income for 2009. This impairment related to the reduced usage of the operating lease for, and certain assets at, the Company s previous headquarters facility located on Pittsburgh s North Shore.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

21. 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)			
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
2010 (a)				
Operating revenues	$ 449,039	$ 270,566	$ 270,859	$ 383,931
Operating income	169,113	78,529	88,182	134,655
Net income	88,065	30,000	36,522	73,113
Earnings per share of common stock:				
Net income				
Basic	$ 0.66	$ 0.20	$ 0.24	$ 0.49
Diluted	$ 0.65	$ 0.20	$ 0.24	$ 0.49

(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 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 2.

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 and September 30, 2011, respectively, reflect the reclassification of the gains on the dispositions of Langley and Big Sandy described in Note 5 into operating income from other income.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

22. 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,		
	2011	2010	2009
		(Thousands)	
At December 31:			
Capitalized costs	$ 5,772,083	$ 4,655,217	$ 3,423,068
Accumulated depreciation and depletion	1,177,526	967,473	797,303
Net capitalized costs	4,594,557	3,687,744	$ 2,625,765
Costs incurred for the years ended December 31:			
Property acquisition:			
Proved properties (b)	$ 108,717	$ 15,359	$ 6,035
Unproved properties	41,085	342,372	24,941
Exploration (c)	2,344	5,105	14,909
Development	928,294	881,331	676,121

(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,		
	2011	2010	2009
		(Thousands)	
Revenues:			
Affiliated	$ 6,225	$ 7,371	$ 6,923
Nonaffiliated	785,060	530,286	414,067
Production costs	80,911	67,414	62,978
Exploration costs	4,932	5,368	17,905
Depreciation, depletion and accretion	257,144	183,699	117,424
Income tax expense	174,835	106,847	84,620
Results of operations from producing activities (excluding corporate overhead)	$ 273,463	$ 174,329	$ 138,063

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 twenty-three 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; production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems; the reserve roll forward 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., who is hired by the Company s

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

management. Since 1937, Ryder Scott Company L.P. 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 Company L.P. reviewed 100% of the total net gas and liquid hydrocarbon proved reserves attributable to the Company s interests as of December 31, 2011. 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,		
	2011	**2010**	**2009**
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	5,205,692	4,056,059	3,097,260
Revision of previous estimates	(393,129)	(606,308)	(94,728)
Purchase of natural gas in place	39,436	2,536	
Sale of natural gas in place	(1,223)	(1,679)	(741)
Extensions, discoveries and other additions	694,180	1,893,387	1,158,602
Production	(197,570)	(138,303)	(104,334)
End of year	5,347,386	5,205,692	4,056,059
Proved developed reserves:			
Beginning of year	2,520,569	2,061,353	1,881,767
End of year	2,948,546	2,520,569	2,061,353

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

	Years Ended December 31,		
	2011	**2010**	**2009**
		(Thousands of Bbls)	
Oil (a)			
Proved developed and undeveloped reserves:			
Beginning of year	2,307	2,016	2,125
Revision of previous estimates	781	411	(10)
Purchase of oil in place	51		
Sale of oil in place			
Production	(208)	(120)	(99)
End of year	2,931	2,307	2,016
Proved developed reserves:			
Beginning of year	2,307	2,016	2,125
End of year	2,931	2,307	2,016

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

As discussed in Note 6, the Company acquired the Class A interest in the Appalachian Natural Gas Trust (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 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 extension, 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.

The Company s 2009 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 1,158.6 Bcfe exceeded the 2009 production of 104.9 Bcfe. Of this increase, approximately 715 Bcfe was attributable to drilling in 2009 that would have qualified as reserve extensions, discoveries and other additions under the previous Security Exchange Commission (SEC) rules, including approximately 400 Bcfe related to offset locations from wells drilled in 2009. The remaining additions are attributable to the SEC s expanded definition of proved reserves in 2009 to include reserves based on reasonable certainty, partially offset by removing reserves that were previously recorded for future vertical wells.

During 2009, the Company recorded downward revisions of 94.8 Bcfe to the December 31, 2008 estimates of its reserves due to decreased prices and other revisions. The new SEC oil and gas reporting rule modified the definition of proved reserves as well as the price used in the calculation which resulted in approximately 55 Bcfe of the 94.8 Bcfe revision of previous estimates. Absent the effect of the new SEC oil and gas reporting rule, the price impact would have been minimal as year-end prices only decreased approximately $0.06 per Dth from 2008.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

During 2009, as a result of the adoption of the new SEC oil and gas reporting rule, previously recorded reserves from vertical well locations were removed and replaced with new reserves from horizontal well locations. This aligned the reserves with the Company s five-year drilling plan. Increases in proved undeveloped reserves in 2009 were primarily due to the ability to add horizontal proved undeveloped location more than one offset location away from existing horizontals.

As of December 31, 2011, 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:

	2011	2010 (Thousands)	2009
Future cash inflows (a) (b) (c)	$ 22,145,953	$ 20,037,125	$ 13,157,580
Future production costs	(3,435,200)	(3,313,378)	(3,804,077)
Future development costs	(2,600,982)	(2,497,312)	(2,929,255)
Future net cash flow before income taxes	16,109,771	14,226,435	6,424,248
10% annual discount for estimated timing of cash flows	(9,887,993)	(9,439,629)	(5,135,935)
Discounted future net cash flows before income taxes	6,221,778	4,786,806	1,288,313
Future income tax expenses, discounted at 10% annually	(2,288,954)	(1,728,594)	(489,559)
Standardized measure of discounted future net cash flows	$ 3,932,824	$ 3,058,212	$ 798,754

(a) The majority of the Company s production is sold through liquid trading points on interstate pipelines. 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, $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 Transcontinental Gas Pipe Line Corp. The Company sold its natural gas processing complex in Langley, Kentucky 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.

(b) The majority of the Company s production is sold through liquid trading points on interstate pipelines. 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, $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 Transcontinental Gas Pipe Line Corp.

(c) The majority of the Company s production is sold through liquid trading points on interstate pipelines. For 2009, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2009 of $58.43 per Bbl of oil, $4.046 per Dth for Columbia Gas Transmission Corp., $4.128 per Dth for Dominion Transmission, Inc., $3.909 per Dth for the East Tennessee Natural Gas Pipeline and $3.920 per Dth for the Tennessee LA 500 Leg of Transcontinental Gas Pipe Line Corp.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011

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, 2011 discounted future net cash flows before income taxes of the Company s proved reserves of approximately $2.3 billion and $8.5 million, respectively.

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

	2011	2010	2009
		(Thousands)	
Sales and transfers of natural gas and oil produced net	$ (710,373)	$ (470,243)	$ (323,225)
Net changes in prices, production and development costs	52,057	807,971	(3,161,428)
Extensions, discoveries and improved recovery, less related costs	806,597	1,739,308	369,075
Development costs incurred	498,175	310,557	560,911
Purchase of minerals in place net	46,178	2,330	
Sale of minerals in place net	(1,124)	(532)	(775)
Revisions of previous quantity estimates	(356,830)	(191,336)	(31,047)
Accretion of discount	478,165	128,741	324,337
Net change in income taxes	(560,360)	(1,239,035)	743,686
Timing and other (a)	622,127	1,171,697	305,085
Net increase (decrease)	874,612	2,259,458	(1,213,381)
Beginning of year	3,058,212	798,754	2,012,135
End of year	$ 3,932,824	$ 3,058,212	$ 798,754

(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 year 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.

23. Subsequent Events

On February 13, 2012, EQT Midstream Partners, LP (the Partnership) filed a registration statement with the SEC relating to a proposed underwritten initial public offering of common units representing limited partner interests in the Partnership. EQT recently formed the Partnership to own, operate, acquire and develop midstream assets in the Appalachian Basin. If the offering is completed, the Company would contribute to the Partnership 100% of Equitrans, LP (Equitrans, the Company s wholly owned interstate pipeline subsidiary). Prior to that contribution, Equitrans would distribute to the Company certain assets currently under construction, subject to FERC approval. As a result, the Partnership would contain approximately 29% of the Midstream segment s assets as of December 31, 2011. The registration statement has not yet become effective. EQT will serve as the general partner of the Partnership and continue to operate this business pursuant to an omnibus agreement and an operation and management services agreement. EQT will continue to consolidate the Partnership results subsequent to the offering.

Table of Contents

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 2011 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, 2011. 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, 2011.

Ernst & Young LLP, 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.

Table of Contents

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 18, 2012, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2011:

- 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, Nominee to Serve for a One-Year Term Expiring in 2013, Nominee to Serve for a Two-Year Term Expiring in 2014 , Nominees to serve for a three year term Expiring in 2015 , Directors Whose Terms Expire in 2013, Directors Whose Terms Expire in 2014 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 heading Executive Officers of the Registrant (as of February 16, 2012), 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 Investor 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, 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 18, 2012, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2011:

- 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

Table of Contents

Committee Interlocks and Insider Participation and Report of the 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 - 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 18, 2012, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2011.

EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2011 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)	3,621,292	$ 40.51 (3)	6,114,338 (4)
Equity Compensation Plans Not Approved by Shareholders (2)	71,274 (5)	N/A	119,119
Total	3,692,566 (5)	$ 40.51 (3)	6,233,457 (4)

(1) Includes the 2009 LTIP including performance share awards under the 2011 VEP, the 2010 EPIPs, the 2010 SIA and deferred stock units and dividends 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 2011 VEP, the 2010 EPIPs and the 2010 SIA.

Table of Contents

(4) 845,682 shares remain available for issuance under the 2008 ESPP and 3,445 shares were subject to purchase at December 31, 2011.

(5) Shares issuable under the Director Deferral Plans consist of: (a) 42,217 shares issuable in connection with a 1999 deferred stock grant payable in common stock of EQT Corporation and including dividends thereon, and (b) 29,057 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 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 retainer. 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 the 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 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 18, 2012, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2011.

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 18, 2012, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2011.

Table of Contents

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 112 through 118) 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.

Table of Contents

EQT CORPORATION AND SUBSIDIARIES

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

FOR THE THREE YEARS ENDED DECEMBER 31, 2011

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses (Income)	Additions Charged to Other Accounts	Deductions (a)	Balance at End of Period
		(Thousands)			
Allowance for doubtful accounts:					
2011	$ 18,335	$ 1,581	$	$ 3,545	$ 16,371
2010	$ 16,792	$ 5,134	$	$ 3,591	$ 18,335
2009	$ 26,636	$ (1,263)	$	$ 8,581	$ 16,792

Note:

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

Table of Contents

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
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	Filed as Exhibit 4.1(a) to Form 10-K for the year ended December 31, 2009
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)	Supplemental Indenture dated as of March 15, 1991 with Bankers Trust Company 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 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(i) to Form 10-K for the year ended December 31, 1995
4.01(g)	Supplemental Indenture dated as of June 30, 2008 between the Company and Deutsche Bank Trust Company Americas 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
4.02(a)	Indenture 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

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

Table of Contents

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
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 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	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 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
4.03(d)	Third Supplemental Indenture dated as of May 15, 2009 between the Company and The Bank of New York 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 EQT Corporation 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

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

113

Table of Contents

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.01(a)	1999 Long-Term Incentive Plan (amended and restated December 2, 2009)	Filed as Exhibit 10.01(a) to Form 10-K for the year ended December 31, 2009
* 10.01(b)	Form of Participant Award Agreement (Restricted Stock) under 1999 Long-Term Incentive Plan (Pre 2007)	Filed as Exhibit 10.05 to Form 10-K for the year ended December 31, 2004
* 10.01(c)	Form of Participant Award Agreement (Restricted Stock) under 1999 Long-Term Incentive Plan (2007 and later)	Filed as Exhibit 10.01(b) to Form 10-K for the year ended December 31, 2006
* 10.01(d)	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(e)	Form of Participant Award Agreement (Stock Option) under the 1999 Long-Term Incentive Plan (post 2007 and later)	Filed as Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2008
* 10.01(h)	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(i)	Form of Participant Award Agreement under the 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(j)	2008 Executive Performance Incentive Program	Filed as Exhibit 10.6 to Form 10-Q for the quarter ended March 31, 2009
* 10.01(k)	Form of Participant Award Agreement under the 2008 Executive Performance Incentive Program	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2008
* 10.01(l)	2009 Shareholder Value Plan	Filed as Exhibit 10.7 to Form 10-Q for the quarter ended March 31, 2009
* 10.01(m)	Form of Participant Award Agreement under the 2009 Shareholder Value Plan	Filed as Exhibit 10.01(m) to Form 10-K for the year ended December 31, 2008
* 10.02(a)	2009 Long-Term Incentive Plan (as amended and restated December 2, 2009)	Filed as Exhibit 10.01(n) to Form 10-K for the year ended December 31, 2009
* 10.02(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2010
* 10.02(c)	Form of Participant Award Agreement (Restricted Stock) under 2009 Long-Term Incentive Plan	Filed as Exhibit 10.01(p) to Form 10-K for the year ended December 31, 2010
* 10.02(d)	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

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Table of Contents

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.02(e)	2010 Executive Performance Incentive Program	Filed as Exhibit 10.01(r) to Form 10-K for the year ended December 31, 2009
* 10.02(f)	Form of Participant Award Agreement under the 2010 Executive Performance Incentive Program	Filed as Exhibit 10.01(s) to Form 10-K for the year ended December 31, 2009
* 10.02(g)	Form of 2010 Stock Incentive Award Agreement	Filed as Exhibit 10.01(t) to Form 10-K for the year ended December 31, 2009
* 10.02(h)	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(i)	2010 July Executive Performance Incentive Program	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010
* 10.02(j)	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(k)	Form of 2011 Value Driver Performance Share Amendment	Filed herewith as Exhibit 10.02(k)
*10.02(l)	Form of Participant Award Agreement (2011 Volume and Efficiency Program)	Filed as 10.1 to Form 10-Q for the quarter ended March 31, 2011
*10.02(m)	2011 Volume and Efficiency Program	Filed as 10.2 to Form 10-Q for the quarter ended March 31, 2011
*10.02(n)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2012 grants)	Filed herewith as Exhibit 10.02(n)
*10.02(o)	Form of Amendment to Stock Option Award Agreements	Filed as 10.3 to Form 10-Q for the quarter ended June 30, 2011
*10.02(p)	Form of 2012 Value Driver Performance Award Agreement	Filed herewith as Exhibit 10.02(p)
*10.02(q)	2012 Executive Performance Incentive Program	Filed herewith as Exhibit 10.02(q)
*10.02(r)	Form of 2012 Executive Performance Incentive Program Award Agreement	Filed herewith as Exhibit 10.02(r)
* 10.03(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
* 10.03(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

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

Table of Contents

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.03(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
* 10.04(a)	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
*10.04(b)	2011 Executive Short-Term Incentive Plan	Filed as Exhibit 10.2 to Form 8-K filed on May 10, 2011
* 10.05	2006 Payroll Deduction and Contribution Program (as amended and restated December 3, 2008)	Filed as Exhibit 10.9 to Form 10-Q for the quarter ended March 31, 2009
* 10.06	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
* 10.07	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
* 10.8(a)	Executive Alternative Work Arrangement Employment Agreement, dated as of May 10, 2011, between the Company and Murry S. Gerber	Filed as Exhibit 10.1 to Form 8-K filed on May 10, 2011
* 10.8(b)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Murry S. Gerber	Filed as Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2008
* 10.8(c)	Change of Control Agreement dated as of September 8, 2008 between the Company and Murry S. Gerber	Filed as Exhibit 10.6 to Form 10-Q for the quarter ended September 30, 2008
* 10.9(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
* 10.9(b)	Change of Control Agreement dated as of September 8, 2008 between the Company and David L. Porges	Filed as Exhibit 10.9 to Form 10-Q for the quarter ended September 30, 2008
* 10.10(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Philip P. Conti	Filed as Exhibit 10.10 to Form 10-Q for the quarter ended September 30, 2008
* 10.10(b)	Change of Control Agreement dated as of September 8, 2008 between the Company and Philip P. Conti	Filed as Exhibit 10.11 to Form 10-Q for the quarter ended September 30, 2008

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Table of Contents

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
* 10.11(c)	Form of Randall L. Crawford Participant Award Agreement under 2007 Supply Long-Term Incentive Program.	Filed as Exhibit 10.11(c) to Form 10-K for the year ended December 31, 2009
*10.11(d)	Change of Control Agreement dated as of September 8, 2008 between the Company and Randall L. Crawford	Filed as 10.3 to Form 10-Q for the quarter ended March 31, 2011
* 10.12(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Lewis B. Gardner	Filed as Exhibit 10.13(a) to Form 10-K for the year ended December 31, 2008
* 10.12(b)	Change of Control Agreement dated as of September 8, 2008 between the Company and Lewis B. Gardner	Filed as Exhibit 10.13(b) to Form 10-K for the year ended December 31, 2008
* 10.13(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement dated as of September 8, 2008 between the Company and Steven T. Schlotterbeck	Filed as Exhibit 10.16(a) to Form 10-K for the year ended December 31, 2008
* 10.13(b)	Change of Control Agreement dated as of September 8, 2008 between the Company and Steven T. Schlotterbeck	Filed as Exhibit 10.16(b) to Form 10-K for the year ended December 31, 2008
* 10.13(c)	Horizontal Drilling Special Grant Award Letters dated as of May 17, 2006 and August 22, 2008 between the Company and Steven T. Schlotterbeck	Filed as Exhibit 10.13 for Form 10-Q for the quarter ended March 31, 2009
* 10.14	Form of Indemnification Agreement between the Company and each executive officer and each outside director	Filed as Exhibit 10.18 to Form 10-K for the year ended December 31, 2008
10.15(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

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Table of Contents

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
31.1	Rule 13(a)-14(a) Certification of Principal Executive Officer	Filed herewith as Exhibit 31.1
31.2	Rule 13(a)-14(a) Certification of Principal Financial Officer	Filed herewith as Exhibit 31.2
32	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	Filed 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 Commission, upon request, copies of instruments with respect to long-term debt, which have not previously been filed.

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Table of Contents

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 16, 2012

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 16, 2012
/s/ PHILIP P. CONTI Philip P. Conti (Principal Financial Officer)	Senior Vice President and Chief Financial Officer	February 16, 2012
/s/ THERESA Z. BONE Theresa Z. Bone (Principal Accounting Officer)	Vice President and Corporate Controller	February 16, 2012
/s/ VICKY A. BAILEY Vicky A. Bailey	Director	February 16, 2012
/s/ PHILIP G. BEHRMAN Philip G. Behrman	Director	February 16, 2012
/s/ KENNETH M. BURKE Kenneth M. Burke	Director	February 16, 2012
/s/ A. BRAY CARY JR. A. Bray Cary Jr.	Director	February 16, 2012
/s/ MARGARET K. DORMAN Margaret K. Dorman	Director	February 16, 2012
/s/ BARBARA S. JEREMIAH Barbara S. Jeremiah	Director	February 16, 2012
/s/ GEORGE L. MILES, JR. George L. Miles, Jr.	Director	February 16, 2012

/s/ JAMES E. ROHR James E. Rohr	Director	February 16, 2012
/s/ DAVID S. SHAPIRA David S. Shapira	Director	February 16, 2012

Table of Contents

/s/ STEPHEN A. THORINGTON Stephen A. Thorington	Director	February 16, 2012
/s/ LEE T. TODD, JR. Lee T. Todd, Jr.	Director	February 16, 2012