EQUITABLE RESOURCES INC /PA/
Form 10-K
February 23, 2007

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, 2006

o 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

EQUITABLE RESOURCES, INC.

(Exact name of registrant as specified in its charter)

PENNSYLVANIA	**25-0464690**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
225 North Shore Drive **Pittsburgh, Pennsylvania**	**15212**
(Address of principal executive offices)	(Zip Code)

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

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

Title of each class	Name of each exchange on which registered
Common Stock, no par value	New York Stock Exchange
Preferred Stock Purchase Rights	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 o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No 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 o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b 2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

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

Yes o No x

The aggregate market value of voting stock held by non-affiliates of the registrant as of June 30, 2006: $3,987,703,990

The number of shares of common stock outstanding as of January 31, 2007: 121,625,746

DOCUMENTS INCORPORATED BY REFERENCE

The Company s definitive proxy statement relating to the annual meeting of shareowners, to be held April 11, 2007, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2006, is incorporated by reference in Part III to the extent described therein.

TABLE OF CONTENTS

Glossary of Commonly Used Terms, Abbreviations, and Measurements

Commonly Used Terms

Appalachian Basin The area of the United States comprised of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie at the foot of 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 and contract pricing.

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

cash flow hedge A derivative instrument that complies with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and is used to reduce the exposure to variability in cash flows from the forecasted physical sale of gas production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted physical sale.

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

dekatherm(dth) A measurement unit of heat energy equal to 1,000,000 British thermal units.

development well A well drilled into a known producing formation in a previously discovered field.

exploratory well A well drilled into a previously untested geologic prospect to determine the presence of gas or oil.

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

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

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

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

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

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.

infill drilling Drilling between producing wells in a developed field to increase production.

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

3

Glossary of Commonly Used Terms, Abbreviations, and Measurements

margin call A demand for additional or variation margin deposits when futures prices move adversely to a hedging party s position.

multiple completion well A well producing oil and/or gas from different zones at different depths in the same well bore with separate tubing strings for each zone.

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 Reserves that, based on geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reserves under existing economic and operating conditions.

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

proved undeveloped reserves Proved reserves that are expected 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) free of cost.

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

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

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

APB No. 18 Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock

APB No. 25 Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees

EITF No. 02-3 Emerging Issues Task Force Issue No. 02-3, Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10 and 00-17

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

FIN 45 FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34

FIN 48 FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109

IRC Internal Revenue Code of 1986

IRS Internal Revenue Service

NYMEX New York Mercantile Exchange

OTC Over the Counter

PA PUC Pennsylvania Public Utility Commission

SEC Securities and Exchange Commission

Glossary of Commonly Used Terms, Abbreviations, and Measurements

SFAS Statement of Financial Accounting Standards

SFAS No. 5 Statement of Financial Accounting Standards No. 5, Accounting for Contingencies

SFAS No. 19 Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies

SFAS No. 69 Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities an amendment of FASB Statements 19, 25, 33, and 39

SFAS No. 71 Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation

SFAS No. 87 Statement of Financial Accounting Standards No. 87, Employers Accounting for Pensions

SFAS No. 88 Statement of Financial Accounting Standards No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits

SFAS No. 106 Statement of Financial Accounting Standards No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions

SFAS No. 109 Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes

SFAS No. 115 Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities

SFAS No. 123 Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation

SFAS No. 123R Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based

Payment

SFAS No. 133 Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended

SFAS No. 143 Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations

SFAS No. 144 Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets

SFAS No. 146 Statement of Financial Accounting Standards No. 146, Accounting for Costs Associated with Exit or Disposal Activities

SFAS No. 157 Statement of Financial Accounting Standards No. 157, Fair Value Measurements

SFAS No. 158 Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132(R)

SFAS No. 159 Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115

WV PSC Public Service Commission of West Virginia

Measurements

Bbl = barrel

Bcf = billion cubic feet

Bcfe = billion cubic feet of natural gas equivalents

Mcf = thousand cubic feet

Mcfe = thousand cubic feet of natural gas equivalents

MMBtu = million British thermal units

MMcf = million cubic feet

MMcfe = million cubic feet of natural gas equivalents

PART I

Forward-Looking 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, forecasts, approximate, expect, project, intend, plan, believe and other words of similar meaning in connection with any discussion of future operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this 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 guidance regarding the Company s drilling and infrastructure programs, production volumes, reserves, capital expenditures, the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc., the financing of that acquisition, and the Company s move to a holding company structure. A variety of factors could cause the Company s actual results to differ materially from the anticipated results or other expectations expressed in the Company s forward-looking statements. 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.

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.

Item 1. Business

General

In this Form 10-K, references to we, us, our, Equitable, Equitable Resources and the Company refer collectively to Equitable Resources, its consolidated subsidiaries, unless otherwise specified.

Equitable Resources, Inc. is an integrated energy company, with an emphasis on Appalachian area natural gas supply activities including production and gathering and natural gas distribution and transmission. The Company and its subsidiaries offer energy (natural gas, and a limited amount of natural gas liquids and crude oil) products and services to wholesale and retail customers through two business segments: Equitable Utilities and Equitable Supply. In December 2005, the Company discontinued and sold the operations of its NORESCO segment, which provided energy efficiency solutions to customers including governmental, military, institutional, commercial and industrial end-users.

The Company was formed under the laws of Pennsylvania by the consolidation and merger in 1925 of two companies, the older of which was organized in 1888. In 1984, the corporate name was changed to Equitable Resources, Inc.

The Company and its subsidiaries had approximately 1,340 employees at the end of 2006, of which 332 employees were subject to collective bargaining agreements. In January 2007, the Company and one union reached agreement on a three-year renewal contract for various clerical employees represented by the union. Although one union representing 14 employees has been operating without a contract since April 19, 2004, the Company believes that its employee relations are generally good.

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 they are filed with 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. Also, these filings are available on the internet at http://www.sec.gov. The

Company s annual reports to shareholders, press releases and recent analyst presentations are also available on the Company s website.

Business Segments

Equitable Utilities

Equitable Utilities operations comprise the gathering, transportation, storage, distribution and sale of natural gas. Equitable Utilities has both regulated and nonregulated operations. The regulated activities consist of the Company s state-regulated distribution operations and federally-regulated pipeline and storage operations. The nonregulated activities include the non-jurisdictional marketing of natural gas, risk management activities for the Company and the sale of energy-related products and services. Equitable Utilities generated approximately –– 36% of the Company s net operating revenues in 2006.

Distribution Operations

Equitable Utilities distribution operations are carried out by Equitable Gas Company (Equitable Gas), a division of the Company. The service territory for the distribution operations includes southwestern Pennsylvania, municipalities in northern West Virginia and field line sales, also referred to as farm tap service, in eastern Kentucky and West Virginia. These areas have a rather static population and economy. The distribution operations provide natural gas services to approximately 274,000 customers, comprising 255,400 residential customers and 18,600 commercial and industrial customers. 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). These contracts contain various pricing mechanisms, ranging from fixed prices to several different index-related prices.

Equitable Gas distribution rates, terms of service, contracts with affiliates and issuance of securities are subject to comprehensive regulation by the PA PUC and the WV PSC. The field line sales rates in Kentucky are also subject to rate regulation by the Kentucky Public Service Commission. Equitable Gas also operates a small gathering system in Pennsylvania, which is not subject to comprehensive regulation.

The Company must usually seek approval of one or more of its regulators prior to increasing (or decreasing) its rates. Currently, Equitable Gas passes through to its regulated customers the cost of its purchased gas and transportation activities. It is allowed to recover a return in addition to the costs of its transportation activities. However, the Company s regulators do not guarantee recovery and may require that certain costs of operation be recovered over an extended term. Equitable Gas has worked with, and continues to work with, regulators to implement alternative performance-based rates. Equitable Gas tariffs for commercial and industrial customers allow for negotiated rates in limited circumstances. Equitable Gas has not filed a base rate case since 1997, and its predominant approach to maximizing value is cost control and operational excellence. Regulators periodically audit the Company s compliance with applicable regulatory requirements. The Company is not aware of any significant non-compliance as a result of any completed audits.

Because most of its customers use natural gas for heating purposes, Equitable Gas revenues are seasonal, with approximately 72% of calendar year 2006 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.

On March 1, 2006, the Company entered into a definitive agreement to acquire Dominion Resources, Inc. s natural gas distribution assets in Pennsylvania and in West Virginia for approximately $970 million, subject to adjustments, in a cash transaction for the stock of The Peoples Natural Gas Company and Hope Gas, Inc. The transaction requires approvals from the PA PUC and the WV PSC and is also under review by the Pennsylvania Attorney General and by the Federal Trade Commission (FTC). On February 9, 2007 an administrative law judge for the PA PUC issued an initial decision approving the stock acquisition, subject to the terms and conditions of the Joint Petition for Settlement filed by the Company and a number of the intervening parties. The Joint Petition for

Settlement includes, among other things, an agreement by the Company that Equitable Gas Company and The Peoples Natural Gas Company will not make base rate case filings prior to January 1, 2009. Under the Commission s rules a period for filing exceptions and reply exceptions has begun to run. Based upon the thorough manner in which the administrative law judge addressed the testimony of opposing parties, the Company believes it likely that the PA PUC will approve the stock acquisition when it reviews the application in March or April of 2007. The WV PSC procedural schedule calls for hearings in mid-May 2007. The WV PSC staff and consumer advocate, the Independent Oil and Gas Association of West Virginia and the Utility Workers Union of America Local 69 Division 1 have intervened in the West Virginia regulatory case. The Company continues to engage in settlement negotiations with these interveners. The Company is complying with the information requests of the Pennsylvania Attorney General and the FTC and is targeting an approval timeframe not long after receiving approval from the PA PUC. No assurance is given that the targeted timeframes will be achieved. The Company s acquisition agreement expires on March 31, 2007 unless a closing has not occurred due to a failure to obtain a required governmental consent or authorization and such is being diligently pursued, in which case the expiration date is automatically extended to June 30, 2007. The agreement will then terminate if no closing occurs by June 30, 2007, unless the parties agree to an extension. The assets to be acquired will increase: customers in the distribution operations by 475,000 or 173%; total storage capacity by 33 Bcf or 60%, miles of gathering pipelines by 936 miles; gathered volumes by 40%; and miles of high pressure transmission by 466 miles or 42%. Transition planning activities have commenced at Equitable Utilities to plan for the integration of the assets, resources, and business processes of The Peoples Natural Gas Company and Hope Gas, Inc. s into Equitable Resources.

Pipeline (Transportation and Storage) Operations

Equitable Utilities interstate pipeline operations are carried out by Equitrans, L.P. (Equitrans). These operations offer gas gathering, transportation, storage and related services to 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 Amerada Hess Corporation. In 2006, approximately 77% of transportation volumes and approximately 62% of transportation revenues were from affiliates.

In the second quarter of 2006, the Company filed a certificate application with the FERC for approval to build a 70-mile, 20-inch diameter pipeline which will connect the Company-operated Kentucky hydrocarbon processing plant in Langley, Kentucky, to the Tennessee Gas Pipeline in Carter County, Kentucky, and will initially provide up to 130,000 dekatherms per day of firm transportation service. The pipeline, known as The Big Sandy Pipeline, is owned and operated by Equitrans and is targeted for completion in 2007. Equitrans has secured most of the materials, labor and rights-of-way necessary to complete the project. Equitrans received a FERC certificate on November 15, 2006, authorizing construction of the pipeline subject to certain operational, commercial and environmental conditions. Equitrans implementation plan addressed those conditions and received FERC approval on November 29, 2006. Capital expenditures incurred by the Company in 2006 related to the Big Sandy Pipeline are included in the Equitable Supply business segment.

Equitrans rates are subject to regulation by the FERC. On April 5, 2006, the FERC approved a settlement to Equitrans consolidated 2005 and 2004 rate case filings. The settlement became effective on June 1, 2006. The settlement provided for the following:

- An expected annual revenue increase of $6.0 million and an expected operating income increase of $3.2 million
- Replenishment of 7.1 Bcf of migrated base gas from prior periods
- Consolidation of transmission assets into a single transmission system with a system-wide rate
- Consolidation of gathering assets into a single gathering system with a system-wide rate
- Tracking and recovery of costs relating to compliance with the Pipeline Safety Improvement Act of 2002
- Redesigned contract storage services
- Five-year rate moratorium on gathering rates
- Three-year rate moratorium on transmission rates

8

Equitrans firm transportation contracts expire between 2007 and 2009. The Company anticipates that the majority of the related volumes will be fully subscribed when they become available.

Energy Marketing

Equitable Utilities unregulated marketing operations include the non-jurisdictional marketing of natural gas at Equitable Gas, marketing and risk management activities at Equitable Energy, LLC (Equitable Energy), and the sale of energy-related products and services by Equitable Homeworks, LLC. Services and products offered by the marketing operations include commodity procurement, delivery and storage services, such as park and loan services, risk management and other services for energy consumers including large industrial, utility, commercial and institutional end-users. Equitable Energy also engages in trading and risk management activities for the Company. The objective of these activities is to limit the Company s exposure to shifts in market prices and to optimize the use of the Company s assets.

Equitable Supply

Equitable Supply s production business develops, produces and sells natural gas and, to a limited extent, crude oil and natural gas liquids, in the Appalachian region of the United States. Its gathering business consists of gathering the Company s and third party gas and the processing of natural gas liquids. Equitable Supply generated approximately 64% of the Company s net operating revenues in 2006.

Production

Equitable Supply s production business, operating through Equitable Production Company and several other affiliates (collectively referred to as Equitable Production), is the largest owner of proved natural gas reserves in the Appalachian Basin. The Company s reserves are located entirely in the Appalachian Basin, where Equitable Production currently operates approximately 12,000 producing wells.

The Appalachian Basin is characterized by wells with comparatively low rates of annual decline in production, long well lives, low production costs per well and high energy content. Many of the Company s wells have been producing for decades, and in some cases since the early 1900 s. Management believes that virtually all of the Company s wells are low risk development wells because they are drilled in areas known to be productive. Many of these wells are completed in more than one producing formation, including coal formations in certain areas, and production from these formations may be commingled. The Company s 2006 drilling program was comprised dominantly of vertical wells, but also included horizontal drilling.

In 2006, Equitable Production drilled 560 gross operated wells (427 net operated wells), including 5 horizontal wells, and 95 gross non-operated wells (28 net non-operated wells) at a success rate of nearly 100%. Drilling was concentrated within Equitable s core areas of southwestern Virginia, southeastern Kentucky and southern West Virginia. This activity resulted in proved developed reserve additions of approximately 120 Bcfe. Of the proved developed reserve additions, approximately 60 Bcfe relates to proved undeveloped reserves that were transferred to proved developed reserves and an equal amount relates to proved developed extensions, discoveries and other additions that were not previously classified as proved.

The natural gas produced by Equitable Supply is a commodity and therefore the Company receives market-based pricing. The market price for gas located in the Appalachian Basin is generally higher than the price for gas located in the Gulf Coast, largely due to the differential in the cost to transport gas to customers in the northeastern United States. The recent increase in production in the Appalachian Basin by the Company and other producers is putting pressure on the capacity of existing gathering and midstream transport systems. As a result, the Company has entered into certain discounted sales arrangements to ensure that its gas continues to flow.

The combination of long-lived production, low drilling costs, high drilling completion rates and proximity to natural gas markets has resulted in a highly fragmented operating environment in the Appalachian Basin. Natural gas drilling activity has increased as suppliers in the Appalachian Basin attempt to take advantage of higher than normal natural gas prices. While increased activity can place constraints on capacity of labor, equipment, pipeline availability and other resources in the Appalachian Basin, it also provides opportunities for expansion of natural gas gathering activities and potential for higher quality rigs and labor providers in the future.

Equitable Supply hedges a portion of its forecasted natural gas production. It also hedges third party purchases and sales. The Company s hedging strategy and information regarding its derivative instruments are outlined in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and in Notes 1 and 3 to the Consolidated Financial Statements.

Gathering

Equitable Gathering derives its revenues from charges to customers for use of its gathering system in the Appalachian Basin. As of December 31, 2006, the system included approximately 7,100 miles of gathering line located throughout West Virginia, eastern Kentucky and southwestern Virginia. Over 85% of the gathering system volumes are transported to interconnects with three major interstate pipelines: Columbia Gas Transmission, East Tennessee Natural Gas Company and Dominion Transmission. The gathering system also maintains interconnects with Equitrans, the Company s interstate pipeline affiliate. Maintaining these interconnects provides the Company with access to geographically diverse markets.

Gathering system sales volumes for 2006 totaled 108.6 Bcfe, of which approximately 64% related to the gathering of Equitable Production s gas volumes, 26% related to third party volumes, and the remainder related to volumes in which interests were sold by the Company but which the Company continued to operate for a fee. Approximately 82% of Equitable Gathering s 2006 revenues were from affiliates. Due to increased operating costs and capital investment, Equitable Gathering is, in certain cases, charging gathering rates which are below its cost of service. Equitable Gathering continues to pursue full recovery of these costs by increasing rates charged to its customers.

Key competitors for new gathering systems include independent gas gatherers and integrated Appalachian energy companies. See Outlook under Equitable Supply s section of Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations for discussion of the Company s strategy in regards to its midstream gathering operations.

Transfer of Gathering Assets

Effective January 1, 2006, certain gathering assets, consisting of 1,400 miles of gathering line and related facilities with approximately 13.3 Bcf of annual throughput, were transferred from Equitable Supply to Equitable Utilities for segment reporting purposes. The effect of the transfer is not material to the results of operations or financial position of the Equitable Utilities or Equitable Supply segments; segment results have not been restated for this transfer.

Discontinued Operations

In the fourth quarter of 2005, the Company sold its NORESCO domestic business for $82 million before customary purchase price adjustments. In the second quarter of 2006, the Company completed the sale of the remaining interest in its investment in IGC/ERI Pan-Am Thermal Generating Limited (Pan Am), previously included in the NORESCO business segment, for total proceeds of $2.6 million. As a result of these transactions, the Company has reclassified its financial statements for all periods presented to reflect the operating results of the NORESCO segment as discontinued operations.

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 during the years 2006, 2005 and 2004.

	2006		2005		2004	
Equitable Utilities:						
Residential natural gas sales	24	%	26	%	29	%
Marketed natural gas sales	30	%	27	%	23	%
Equitable Supply:						
Natural gas equivalents sales	29	%	30	%	29	%

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.

Financial Information About Geographic Areas

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

Environmental

See Note 19 to the Consolidated Financial Statements for information regarding environmental matters.

Item 1A. Risk Factors

Risks Relating to Our Business

In addition to the other information contained in this Form 10-K, the following risk factors should be considered in evaluating our business. 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.

Natural gas price volatility may have an adverse effect on our revenue, profitability and liquidity.

Our revenue, profitability and liquidity depend on 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 proximity to, and availability of capacity on, transportation facilities; and government regulations, such as regulation of natural gas transportation, royalties and price controls.

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, such as occurred in the fall and winter of 2005, subject us to margin calls on our commodity price derivative contracts (hedging arrangements, including futures contracts, swap agreements and exchange traded instruments) which 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 such cases we are, however, exposed to the risk of non-performance by our hedge counterparties of their obligations under the derivative contracts. 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 the increase in the price of natural gas.

Lower natural gas prices, increases in our estimates of development costs or changes to our production assumptions may result in our having to make downward adjustments to our estimated proved reserves, change our production plans, and incur non-cash charges to earnings.

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. 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.

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

Our gas delivery depends on the availability of adequate transportation infrastructure. We have announced a significant investment in transportation infrastructure (the Big Sandy Pipeline) which is intended to address a lack of capacity on and access to existing transportation pipelines as well as curtailments on such pipelines. We are also planning an upgrade to the Company-operated hydrocarbon processing plant in Langley, Kentucky for completion in early 2008. Our infrastructure development program can involve significant risks, including those related to timing and cost overruns and these risks can be affected by the availability of capital, materials, and a qualified work force, as well as weather conditions, gas price volatility, government approvals, title problems, geology and other factors. In addition, we may not be able to obtain sufficient third party transportation contracts to recover the costs of our infrastructure development program. We also deliver to and are served by third party gas gathering, transportation, processing and storage facilities which are limited in number and geographically concentrated. An extended interruption of access to or service from these facilities could result in material adverse consequences to us.

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 on our ability to develop additional gas reserves that are economically recoverable and to maximize existing well production, and our failure to do so may reduce our earnings. We have expanded our drilling program in recent years, and we have subsequently announced further expansion. Our drilling of development wells can involve significant risks, including those related to timing and cost overruns and these risks can be affected by the availability of capital, leases, rigs and a qualified work force, as well as weather conditions, gas price volatility, government approvals, title problems, geology 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 due to inadequate well operation and compressor availability. Without continued successful development or acquisition activities, our reserves and revenues will decline as a result of our current reserves being depleted by production.

We may engage in acquisition and disposition strategies that involve a number of inherent risks, any of which may cause us not to realize anticipated benefits and may adversely affect our earnings, cash flows and results of operations.

On March 1, 2006, we signed a purchase agreement to acquire the capital stock of The Peoples Natural Gas Company and Hope Gas, Inc. from Consolidated Natural Gas Company, a wholly-owned subsidiary of Dominion Resources, Inc. In addition, we intend to continue to strategically position our business in order to improve our ability to compete. Acquisitions, joint ventures and other business combinations involve various inherent risks, such as assessing the value, strengths, weaknesses, contingent and other liabilities and potential profitability of acquisition or other transaction candidates; the potential loss of key personnel of an acquired business; the constraints imposed by regulators in approving such transactions; the potential for unions of an acquired business to strike; our ability to achieve identified financial and operating synergies anticipated to result from an acquisition or other transaction; demands on management related to the increase in size after an acquisition or other transaction; and unanticipated changes in business and economic conditions affecting an acquisition or other transaction. We may be unable to realize, or do so within any particular time frame, the cost reductions, cash flow increases or other synergies expected to result from such transactions. In addition, various factors including prevailing market conditions and the incursion of related contingent liabilities could negatively impact the benefits we receive from transactions.

If we fail to achieve our strategic or financial goals in any acquisition or disposition transaction, it could have a significant adverse affect on our earnings, cash flows and results of operations. Furthermore, if we borrow money to finance an acquisition, which we plan to do in connection with the acquisition of The Peoples Natural Gas Company and Hope Gas, Inc., our failure to achieve our stated goals could impact our ability to repay such borrowings or other borrowings and could weaken our financial condition. Moreover, additional debt could increase our vulnerability to the effects of interest rate movements.

We are subject to risks associated with the operation of our 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. 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. As a result, we are sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business. There can be no assurance that insurance policies we maintain to limit our liability of such losses will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that such levels of insurance will be available in the future at economical prices.

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.

Significant portions of our gathering, transportation, storage and distribution businesses are subject to state and federal regulation including regulation of the rates which we may assess our customers. 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.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities relating to protection of the environment and health and safety matters, including those legal requirements that 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, restoration of drilling properties after drilling is completed, pipeline safety and work practices related to employee health and safety. Complying with these requirements could have a significant effect on our costs of operations and competitive position. If we fail to comply with these requirements, even if caused by factors beyond our control, such failure could result in the assessment of civil or criminal penalties and damages against us.

The rates of federal, state and local taxes applicable to the industries in which we operate, including production taxes paid by Equitable Supply, which often fluctuate, could be increased by the respective taxing authorities. In addition, the tax laws, rules and regulations that affect our business could change. Any such increase or change could adversely impact our cash flows and profitability.

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 by the Company s business segments, with the exception of various office locations and warehouse buildings, which are leased. A limited amount of equipment is also leased. The majority of the Company s properties are located on or under (1) public highways under franchises or permits from various governmental authorities, or (2) private properties owned in fee, or occupied under perpetual easements or other rights acquired for the most part without examination of underlying land titles. The Company s facilities are generally well maintained and, where necessary, are replaced or expanded to meet operating requirements.

Headquarters. In May 2005, the Company completed the relocation of its corporate headquarters and other operations to a newly constructed office building, which the Company leases, located at the North Shore in Pittsburgh, Pennsylvania. The Company still maintains leases for properties previously used for its administrative operations that were not being utilized for a period of time following the relocation and were deemed to have no economic benefit to the Company. However, during the second quarter of 2006, the Company began to utilize certain of the leased space previously deemed to have no economic benefit to the Company for the transition planning activities relating to the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc.

Equitable Utilities. This segment owns and operates natural gas distribution properties as well as other general property and equipment in western Pennsylvania, West Virginia and Kentucky. The segment also owns and operates underground storage, transmission and gathering facilities in Pennsylvania and West Virginia.

The distribution operations consist of approximately 4,100 miles of pipe in Pennsylvania, West Virginia and Kentucky. The interstate pipeline operations consist of approximately 2,900 miles of transmission, storage, and gathering lines and interconnections with five major interstate pipelines. The interstate pipeline system stretches throughout north central West Virginia and southwestern Pennsylvania. Equitrans has 15 natural gas storage reservoirs with approximately 496 MMcf per day of peak delivery capability and 57 Bcf of storage capacity of which 27 Bcf is working gas. These storage reservoirs are clustered, with 8 in northern West Virginia and 7 in southwestern Pennsylvania.

Equitable Supply. This segment s production and gathering properties are located in the Appalachian Basin, specifically Kentucky, Pennsylvania, Virginia and West Virginia. This segment currently has an inventory of approximately 3.3 million gross acres (approximately 71% of which is considered undeveloped), which encompasses nearly all of the Company s acreage of proved developed and undeveloped natural gas and oil production properties. Although most of its wells are drilled to relatively shallow depths (2,000 to 6,500 feet below the surface), the Company retains what are normally considered deep rights on the majority of its acreage. As of December 31, 2006, the Company estimated its total proved reserves to be 2,497 Bcfe, including proved undeveloped reserves of 772 Bcfe. 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 24 (unaudited) to the Consolidated Financial Statements.

Natural Gas and Crude Oil Production:

	2006	**2005**	**2004**
Natural Gas:			
MMcf produced	80,698	78,105	72,226
Average well-head sales price per Mcfe sold (net of hedges)	$ 4.79	$ 5.13	$ 4.45
Crude Oil:			
Thousands of Bbls produced	112	108	83
Average sales price per Bbl	$ 58.35	$ 53.07	$ 37.38

Average production cost, including severance taxes (lifting cost), of natural gas and crude oil during 2006, 2005, and 2004 was $0.768, $0.771, and $0.583 per Mcfe, respectively.

	Natural Gas	**Oil**
Total productive wells at December 31, 2006:		
Total gross productive wells	12,402	22
Total net productive wells	9,270	19

At December 31, 2006, the Company had approximately 117 multiple completion wells.

Total acreage at December 31, 2006:	
Total gross productive acres	964,840
Total net productive acres	906,950
Total gross undeveloped acres	2,330,550
Total net undeveloped acres	2,191,833

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

	2006	**2005**	**2004**
Exploratory wells:			
Productive			
Dry			
Development wells:			
Productive	455.0	344.2	246.5
Dry	1.0	1.0	

Selected data by state (at December 31, 2006 unless otherwise noted):

		Kentucky	Virginia	West Virginia	Pennsylvania	Ohio(a)	Total
Natural gas and oil production (MMcfe)	2006	35,699	23,723	20,534	1,415		81,371
Natural gas and oil production (MMcfe)	2005	33,849	21,913	19,924	2,247	822	78,755
Natural gas and oil production (MMcfe)	2004	30,183	20,497	18,019	2,415	1,646	72,760
Net revenue interest (%)		84.3 %	67.5 %	61.5 %	88.4 %		72.3 %
Total gross productive wells		4,876	2,223	4,621	704		12,424
Total net productive wells		4,047	1,754	2,784	704		9,289
Total gross acreage		1,442,481	527,284	1,201,304	124,321		3,295,390
Total net acreage		1,379,615	507,992	1,086,923	124,253		3,098,783
Proved developed reserves (Bcfe)		886	337	472	30		1,725
Proved undeveloped reserves (Bcfe)		339	98	335			772
Proved developed and undeveloped reserves (Bcfe)		1,225	435	807	30		2,497
Gross proved undeveloped drilling locations		1,069	656	1,189			2,914
Net proved undeveloped drilling locations		1,050	375	1,174			2,599
Approximate miles of gathering line		3,300	1,200	2,600			7,100

(a) Relates to certain non-core gas properties sold in May 2005. See Note 4 to the Company s Consolidated Financial Statements.

Wells located in Kentucky are primarily in shale formations with depths ranging from 2,500 feet to 6,000 feet and average spacing of 72 acres. Wells located in Virginia are primarily in coal bed methane formations with depths ranging from 2,000 feet to 3,000 feet and average spacing of 60 acres. Wells located in West Virginia are primarily in tight sand formations with depths ranging from 2,500 feet to 6,500 feet and average spacing of 40 acres in the northern part of the state and 60 acres in the southern part of the state. Wells located in Pennsylvania are primarily in tight sand formations with depths ranging from 3,000 feet to 5,000 feet and average spacing of 40 acres.

The gathering operations own or operate approximately 7,100 miles of gathering line and 180 compressor units comprising 107 compressor stations with approximately 123,000 horse power of installed capacity, as well as other general property and equipment.

Substantially all of Equitable Supply s sales are delivered to several large interstate pipelines on which the Company leases capacity. These pipelines are subject to periodic curtailments for maintenance and repairs.

Equitable Supply leases office space in Pennsylvania, West Virginia, Virginia and Kentucky.

16

Item 3. Legal Proceedings

In the ordinary course of business, various legal 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 has established reserves for pending litigation, which it believes are adequate, 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 of the Company.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of the Company s security holders during the last quarter of its fiscal year ended December 31, 2006.

Executive Officers of the Registrant (as of February 21, 2007)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
John A. Bergonzi (54)	Vice President and Corporate Controller (2003)	Elected to present position January 2003; Corporate Controller and Assistant Treasurer from December 1995 to December 2002.
Philip P. Conti (47)	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, also Treasurer until January 2006; Vice President, Finance and Treasurer from August 2000 to January 2005.
Randall L. Crawford (44)	Senior Vice President, and President, Equitable Utilities (2003)	Elected to present position February 2007; Vice President, and President, Equitable Utilities from February 2004 to February 2007; President, Equitable Gas Company from January 2003 to January 2004; Executive Vice President, Equitable Gas Company from November 2000 to December 2002.
Martin A. Fritz (42)	Vice President and Chief Administrative Officer (2006)	Elected to present position February 2007; Vice President and Chief Information Officer from April 2006 to February 2007; Chief Information Officer from May 2003 to March 2006; Deputy General Counsel from April 1999 to April 2003.
Murry S. Gerber (53)	Chairman and Chief Executive Officer (1998)	Elected to present position February 2007; Chairman, President and Chief Executive Officer from May 2000 to February 2007; President and Chief Executive Officer from June 1, 1998 to February 2007.
Joseph E. O Brien (54)	Senior Vice President, and President, Equitable Supply (2001)	Elected to present position February 2007; Vice President, and President Equitable Supply from February 2006 to February 2007; Vice President, Facility Construction from July 2005 to January 2006. President, NORESCO, LLC from January 2000 to June 2005.
Johanna G. O Loughlin (60)	Senior Vice President, General Counsel and Corporate Secretary (1996)	Elected to present position January 2002; Vice President, General Counsel and Secretary from May 1999 to January 2002.
Charlene Petrelli (46)	Vice President and Chief Human Resources Officer (2003)	Elected to present position February 2007; Vice President, Human Resources from January 2003 to February 2007; Director of Corporate Human Resources from October 2000 to December 2002.
David L. Porges (49)	Vice Chairman, President and Chief Operating Officer (1998)	Elected to present position February 2007; Vice Chairman and Executive Vice President, Finance and Administration from January 2005 to February 2007; Executive Vice President and Chief Financial Officer from February 2000 to January 2005.

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

PART II

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

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

	2006 High	Low	Dividend	2005 (a) High	Low	Dividend
1st Quarter	$ 39.02	$ 34.05	$ 0.21	$ 30.62	$ 27.89	$ 0.19
2nd Quarter	37.00	31.59	0.22	34.42	28.16	0.21
3rd Quarter	37.48	32.55	0.22	39.90	34.01	0.21
4th Quarter	44.48	34.83	0.22	41.18	34.51	0.21

(a) Adjusted to reflect the two-for-one stock split effective September 1, 2005.

As of February 12, 2007, there were 3,992 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, the Company s results of operations and financial condition and other factors. Based on currently foreseeable market conditions, the Company anticipates that comparable dividends will be paid on a regular quarterly basis.

The following table sets forth the Company s repurchases of equity securities registered under Section 12 of the Exchange Act that have occurred in the three months ended December 31, 2006.

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 (b)
October 2006 (October 1 October 31)	12,941	$ 37.82		8,385,400
November 2006 (November 1 November 30)	9,721	$ 42.86		8,385,400
December 2006 (December 1 December 31)	8,235	$ 43.31		8,385,400
Total	30,897			

(a) Includes 16,724 shares delivered in exchange for the exercise of stock options to cover award cost and 14,173 shares for Company-directed purchases made by the Company s 401(k) plans.

(b) Equitable s Board of Directors previously authorized a share repurchase program with a maximum of 50.0 million shares and no expiration date. The program was initially publicly announced on October 7, 1998, with subsequent amendments announced on November 12, 1999, July 20, 2000, April 15, 2004 and July 13, 2005.

19

Stock Performance Graph

The following graph compares the most recent five-year cumulative total return attained by shareholders of Equitable Resources common stock with the cumulative total returns of the S & P 500 index, and a customized peer group of eleven companies listed in footnote 1 below whose principal businesses are natural gas distribution, exploration and production, and transmission. An investment of $100 (with reinvestment of all dividends) is assumed to have been made on December 31, 2001 in the Company s common stock, in the S&P 500 index, and in the peer group. Relative performance is tracked through December 31, 2006.

	2001	**2002**	**2003**	**2004**	**2005**	**2006**
EQUITABLE RESOURCES, INC.	100.00	104.90	131.69	191.65	237.77	277.02
SELF-CONSTRUCTED PEER GROUP (1)	100.00	88.54	110.19	137.39	167.99	203.86
S & P 500	100.00	77.90	100.24	111.15	116.61	135.03

(1) The following eleven companies are included in the customized peer group: CMS Energy Corporation, Energen Corporation, Keyspan Corporation, Kinder Morgan, Inc, National Fuel Gas Company, NiSource Inc, OGE Energy Corp., ONEOK, Inc, Peoples Energy Corp., Questar Corporation and Southwestern Energy Company. This is the same peer group used for the company s short-term incentive plans. The company uses other peer groups for other purposes, including its executive performance incentive program under the 1999 Long-Term Incentive Plan.

Item 6. Selected Financial Data

	As of and for the year ended December 31, (a) 2006	2005	2004	2003	2002
	(Thousands, except per share amounts)				
Operating revenues	$ 1,267,910	$ 1,253,724	$ 1,045,183	$ 876,574	$ 878,961
Income from continuing operations before cumulative effect of accounting change (b)	$ 216,025	$ 258,574	$ 298,790	$ 165,750	$ 145,731
Income from continuing operations before cumulative effect of accounting change per share of common stock (c)					
Basic	$ 1.79	$ 2.14	$ 2.42	$ 1.34	$ 1.16
Diluted	$ 1.77	$ 2.09	$ 2.37	$ 1.31	$ 1.14
Total assets	$ 3,256,911	$ 3,342,285	$ 3,205,346	$ 2,948,073	$ 2,440,396
Long-term debt	$ 753,500	$ 766,500	$ 626,500	$ 647,000	$ 471,250
Preferred trust securities	$	$	$	$	$ 125,000
Cash dividends declared per share of common stock (c)	$ 0.870	$ 0.820	$ 0.720	$ 0.485	$ 0.335

(a) Amounts have been reclassified to reflect the operating results of the NORESCO segment as discontinued operations for all periods presented.

(b) The year ended December 31, 2003, excludes the negative cumulative effect of an accounting change of $3.6 million related to the adoption of SFAS No. 143. The year ended December 31, 2002, excludes the negative cumulative effect of accounting change of $5.5 million related to the adoption of SFAS No. 142 and income from discontinued operations of $9.0 million related to the sale of the Company s natural gas midstream operations.

(c) All per share amounts have been adjusted for the two-for-one stock split effected on September 1, 2005.

See Item 1A, Risk Factors, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Notes 4 and 5 to the Consolidated Financial Statements for other matters that affect the comparability of the selected financial data as well as uncertainties that might affect the Company s future financial condition.

21

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

Consolidated Results of Operations

Equitable s consolidated income from continuing operations for 2006 was $216.0 million, or $1.77 per diluted share, compared with $258.6 million, or $2.09 per diluted share, for 2005, and $298.8 million, or $2.37 per diluted share, for 2004.

The $42.6 million decrease in income from continuing operations from 2005 to 2006 included the impact of several factors. In 2005, the Company recognized a pre-tax gain of $110.3 million on the sale of Kerr-McGee Corporation (Kerr-McGee) shares. In 2006, the Company incurred $12.3 million of transition planning expenses relating to the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc. The Company also established a reserve for West Virginia royalty disputes. The impact of lower realized selling prices ($25.8 million) and warmer weather ($9.3 million) also contributed to the decrease between years.

Decreases in income from continuing operations between years were partially offset by 2005 charges of $16.0 million for the termination and settlement of certain defined benefit pension plans and of $7.8 million for the Company s office consolidation, as well as the 2006 favorable impact of the Equitrans rate case settlement. Additionally, income from continuing operations for 2006 was positively impacted by reduced expenses related to the executive performance incentive programs ($22.7 million), favorable storage asset optimization ($16.4 million), and higher production sales volumes ($11.6 million).

The $40.2 million decrease in income from continuing operations from 2004 to 2005 was primarily the result of several factors. The Company recorded a gain in 2004 as a result of the Westport Resources Corporation (Westport)/Kerr-McGee merger in the second quarter of 2004 as well as a gain on the sale of 0.8 million Kerr-McGee shares subsequent to the merger. These gains were partially offset by an expense related to the Company s charitable contribution of 0.4 million Kerr-McGee shares to the Equitable Resources Foundation, Inc. in 2004. The 2005 gain from the sale of the Company s remaining Kerr-McGee shares partially offset the impact of the 2004 items.

Income from continuing operations was favorably impacted in 2005 compared to 2004 as a result of higher realized selling prices, an increase in sales volumes from production and increased revenues from storage asset optimization. These increases were offset in some part by increased operating costs resulting primarily from higher natural gas prices and sales volumes, increased incentive expenses and impairment charges related to the Company s office consolidation.

The Company s effective tax rate for its continuing operations for the year ended December 31, 2006, was 33.7% compared to 37.2% for the year ended December 31, 2005, and 34.2% for the year ended December 31, 2004. The higher effective tax rate in 2005 was primarily the result of tax benefit disallowances under Section 162(m) of the IRC. See Note 6 to the Consolidated Financial Statements.

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, equity in earnings of nonconsolidated investments, and other income, net. Interest expense and income taxes are managed on a consolidated basis. Headquarters costs are billed to the operating segments based upon a fixed allocation of the headquarters annual operating budget. Differences between budget and actual headquarters expenses are not allocated to the operating segments. Certain performance-related incentive costs, pension costs and administrative costs totaling $21.9 million, $48.0 million and $45.8 million in 2006, 2005 and 2004, respectively, were not allocated to business segments. The decrease in unallocated expenses from 2005 to 2006 was primarily related to decreased long-term incentive expenses.

The Company has reconciled each segment s operating income, equity in earnings of nonconsolidated investments and other income, net to the Company s consolidated operating income, equity in earnings of nonconsolidated investments and other income, net totals in Note 2 to the Consolidated Financial Statements.

Additionally, these subtotals are reconciled to the Company s consolidated net income in Note 2. The Company has also 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. Equitable s management believes that presentation of this information is useful to management and investors in assessing the financial condition, operations and trends of each of Equitable s segments without being obscured by the financial condition, operations and trends for the other segments or by the effects of corporate allocations. In addition, management uses these measures for budget planning purposes.

Equitable Utilities

Overview

Equitable Utilities net operating revenues increased 8.5% from 2005 to 2006. This increase was primarily due to increased pipeline revenues from the settlement of the Equitrans rate case effective June 1, 2006, as well as favorable marketing revenues resulting from volatile natural gas prices, as the marketing operations were able to take advantage of their asset position and achieve record margins from that business in 2006. The marketing business is primarily driven by Equitable Utilities physical and contractual gas storage assets which allow the segment to purchase gas and store it in lower price markets and simultaneously enter into contracts to sell it later at higher prices, taking advantage of near term seasonal gas price spreads. Those spreads are unpredictable and at times were considerably wider in 2006 than they were in 2005.

The positive results from the pipeline and marketing operations were partially offset by reduced revenues in Equitable Utilities distribution operations, as the weather in Equitable Gas service territory in 2006 was 15% warmer than the 30 year average and 10% warmer than 2005. The National Oceanic and Atmospheric Administration (NOAA) reported that the 2006 average annual temperature for the contiguous U.S. was the warmest on record. NOAA also reported that, based on the unusually warm temperatures during much of the first half of the winter season (October to December 2006), the nation s residential energy demand was approximately 13.5 percent lower than what would have occurred under average climate conditions for the season.

Operating expenses at Equitable Utilities decreased 3%, driven primarily by the absence of charges related to pension plans and the Company s office consolidation that occurred in 2005, offset somewhat by transition planning expenses incurred in 2006 related to the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc. and the recognition of costs previously deferred as a result of the Equitrans rate case settlement.

Expenses were also positively impacted by a reduction in bad debt expense. In 2006, Equitable continued its consistent and aggressive collections strategy as permitted by The Responsible Utility Customer Protection Act, which became effective on December 14, 2004. In December 2005, the PA PUC approved Equitable Gas s petition requesting approval to use up to $7 million of pipeline supplier refunds to benefit low-income customers in its service territory, primarily during the winter heating season. Approximately $4.9 million and $0.3 million of this amount was credited to eligible customers accounts during 2006 and 2005, respectively. The execution of the collections strategy and provision of additional customer energy assistance enabled Equitable Utilities to reduce its delinquent customer base by 20% as of December 2006 compared to December 2005. These efforts were significant in enabling Equitable Utilities to reduce its bad debt expense in 2006, despite unusually high gas cost rates in effect during 2006 and 2005.

On March 1, 2006, the Company entered into a definitive agreement to acquire Dominion Resources, Inc. s natural gas distribution assets in Pennsylvania and in West Virginia for approximately $970 million, subject to adjustments, in a cash transaction for the stock of The Peoples Natural Gas Company and Hope Gas, Inc. The transaction requires approvals from the PA PUC and the WV PSC and is also under review by the Pennsylvania Attorney General and by the Federal Trade Commission (FTC). On February 9, 2007 an administrative law judge for the PA PUC issued an initial decision approving the stock acquisition, subject to the terms and conditions of the Joint Petition for Settlement filed by the Company and a number of the intervening parties. The Joint Petition for Settlement includes, among other things, an agreement by the Company that Equitable Gas Company and The Peoples Natural Gas Company will not make base rate case filings prior to January 1, 2009. Under the Commission s rules a period for filing exceptions and reply exceptions has begun to run. Based upon the thorough manner in which the administrative law judge addressed the testimony of opposing parties, the Company believes it likely that the PA PUC will approve the stock acquisition when it reviews the application in March or April of 2007. The WV PSC procedural schedule calls for hearings in mid-May 2007. The WV PSC staff and consumer advocate, the Independent Oil and Gas Association of West Virginia and the Utility Workers Union of America Local 69 Division 1 have intervened in the West Virginia regulatory case. The Company continues to engage in settlement negotiations with these interveners. The Company is complying with the information requests of the Pennsylvania Attorney General and the FTC and is targeting an approval timeframe not long after receiving approval from the PA PUC. No assurance is given that the targeted timeframes will be achieved. The Company s acquisition agreement expires on March 31, 2007 unless a closing has not occurred due to a failure to obtain a required governmental consent or authorization and such is being diligently pursued, in which case the expiration date is automatically extended to June 30, 2007. The agreement will then terminate if no closing occurs by June 30, 2007, unless the parties agree to an extension.

With the relatively recent repeal of the Public Utility Holding Company Act of 1935, the Company has filed applications with the PA PUC and WV PSC to reorganize as a holding company. Currently, Equitable Gas is a division of Equitable Resources, Inc., which requires the Company to obtain regulatory approval for many actions that are not directly related to the distribution operations, such as acquisitions and financings. This requirement restricts the Company s ability to take advantage of opportunities and market conditions. The Company successfully completed a request for direction to holders of notes under the indentures governing its long-term debt. Upon receipt of the other required approvals, the Company expects to complete the reorganization. In 2006, the Company expensed $1.6 million of costs related to the holding company implementation.

Results of Operations

	Years Ended December 31, 2006	2005	% change 2006 - 2005	2004	% change 2005 - 2004
OPERATIONAL DATA					
Heating degree days (30 year average = 5,829)	4,976	5,543	(10.2)	5,360	3.4
Residential sales and transportation volume (MMcf)	21,014	24,680	(14.9)	25,520	(3.3)
Commercial and industrial volume (MMcf)	23,841	25,368	(6.0)	29,597	(14.3)
Total throughput (MMcf) Distribution Operations	44,855	50,048	(10.4)	55,117	(9.2)
Net operating revenues (thousands):					
Distribution Operations (regulated):					
Residential	$ 92,497	$ 102,457	(9.7)	$ 104,612	(2.1)
Commercial & industrial	42,519	46,857	(9.3)	48,563	(3.5)
Other	8,319	7,544	10.3	5,950	26.8
Total Distribution Operations	143,335	156,858	(8.6)	159,125	(1.4)
Pipeline Operations (regulated)	72,586	53,767	35.0	55,123	(2.5)
Energy Marketing	59,089	42,739	38.3	28,457	50.2
Total net operating revenues	$ 275,010	$ 253,364	8.5	$ 242,705	4.4
Total operating expenses as a % of net operating revenues	54.47 %	61.22 %		55.44 %	
Operating income (thousands):					
Distribution Operations (regulated)	$ 34,807	$ 40,322	(13.7)	$ 56,877	(29.1)
Pipeline Operations (regulated)	33,240	17,345	91.6	24,656	(29.7)
Energy Marketing	57,162	40,587	40.8	26,616	52.5
Total operating income	$ 125,209	$ 98,254	27.4	$ 108,149	(9.1)
Depreciation, depletion and amortization (DD&A) (thousands):					
Distribution Operations	$ 19,938	$ 19,483	2.3	$ 17,474	11.5
Pipeline Operations	8,737	8,317	5.0	7,985	4.2
Energy Marketing	56	74	(24.3)	170	(56.5)
Total DD&A	$ 28,731	$ 27,874	3.1	$ 25,629	8.8
Capital expenditures (thousands)	$ 64,974	$ 61,349	5.9	$ 56,274	9.0

	Years Ended December 31, 2006	2005	% change 2006 - 2005	2004	% change 2005 - 2004
FINANCIAL DATA (thousands)					
Distribution revenues (regulated)	$ 445,168	$ 469,102	(5.1)	$ 422,438	11.0
Pipeline revenues (regulated)	74,010	57,534	28.6	55,123	4.4
Marketing revenues	380,149	365,625	4.0	300,513	21.7
Less: intrasegment revenues	(56,163)	(45,804)	22.6	(46,213)	(0.9)
Total operating revenues	843,164	846,457	(0.4)	731,861	15.7
Purchased gas costs	568,154	593,093	(4.2)	489,156	21.2
Net operating revenues	275,010	253,364	8.5	242,705	4.4
Operating expenses:					
Operating and maintenance (O & M)	58,186	57,315	1.5	52,481	9.2
Selling, general and administrative (SG&A)	65,280	66,080	(1.2)	56,446	17.1
Impairment charges	(2,396)	3,841	(162.4)		100.0
DD&A	28,731	27,874	3.1	25,629	8.8
Total operating expenses	149,801	155,110	(3.4)	134,556	15.3
Operating income	$ 125,209	$ 98,254	27.4	$ 108,149	(9.1)

Fiscal Year Ended December 31, 2006 vs. December 31, 2005

Equitable Utilities operating income totaled $125.2 million for 2006 compared to $98.3 million for 2005. Equitable Utilities operating income increased $26.9 million primarily due to increased net marketing revenues, lower expenses related to defined benefit pension plans, increased pipeline operating income, reduction in bad debt expense, an impairment charge in 2005 in connection with the Company s office consolidation and a gain in 2006 as a result of the partial reversal of the office impairment charge recorded in 2005. These improvements are partially offset by the impact of costs incurred in planning for the pending acquisition of The Peoples Natural Gas Company and Hope Gas Inc. and a reduction in distribution gas sales margins due to weather 15% warmer than the 30-year average.

Net operating revenues were $275.0 million for 2006 compared to $253.4 million for 2005. The $21.6 million increase in net operating revenues was primarily due to increased pipeline and marketing net operating revenues, partially offset by lower distribution net operating revenues. Pipeline operations net operating revenues increased $18.8 million from 2005 to 2006 primarily due to the settlement of Equitrans 2003 FERC rate case and the implementation of new rates and contracts in connection with that settlement. The settlement s approval, which occurred in April 2006, improved net operating revenues by $7.0 million related to years 2005 and prior and an additional $5.7 million related to the transfer of certain gathering assets from Equitable Supply. New contract rates and billing determinants in the settlement result in the remaining $6.1 increase in pipeline net operating revenues. The increase in marketing net operating revenues of $16.4 million resulted primarily from increased storage asset opportunities realized in the volatile natural gas commodity price environment. Distribution operations net operating revenues decreased $13.5 million primarily due to decreased residential sales and transportation volumes, which decreased 3,666 MMcf from 2005 to 2006 due primarily to warmer weather.

Operating expenses totaled $149.8 million for 2006 compared to $155.1 million for 2005. Operating expenses for 2005 included $16.0 million in charges related to the termination and settlement of certain defined benefit pension plans and a $3.8 million loss related to the impairment of certain leased offices, furniture and equipment in connection with the Company s relocation into its new, consolidated office space. Operating expenses for 2006 include $12.3 million of costs incurred in planning for the pending acquisition of The Peoples Natural Gas

Company and Hope Gas, Inc.; a $2.9 million increase in gathering expenses as a result of the transfer of certain assets from Equitable Supply; the recognition of $4.6 million of previously deferred post-retirement benefit obligation expenses in the pipeline business, both in connection with the FERC rate case settlement; and the reversal of $2.4 million of the 2005 office impairment charge, as the space previously abandoned was put back into use for the transition planning activities relating to the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc. Excluding these items, operating expenses decreased $2.9 million, which was primarily a result of decreases in distribution and marketing bad debt expense totaling $5.2 million, offset by increases of $0.9 million in depreciation expense and $0.8 million in general liability insurance expenses. The improvements in bad debt expense are a result of the more timely termination of non-paying customers, improved efforts to obtain alternative funding for low income customers and other improvements in the collections process. The increased depreciation expense is a result of increased capital spending in Equitable Utilities over the past two years and is primarily related to computer hardware and software, distribution mainline and service line replacements and the installation of automated meter reading devices.

Fiscal Year Ended December 31, 2005 vs. December 31, 2004

Equitable Utilities operating income totaled $−−98.3 million for 2005 compared to $108.1 million for 2004. Net operating income for 2005 included charges for the termination and settlement of defined benefit pension plans and an impairment charge in connection with the Company s office consolidation.

Net operating revenues were $253.4 million for 2005 compared to $242.7 million for 2004. The $10.7 million increase in net operating revenues was primarily due to increased marketing net operating revenues of $14.2 million, resulting primarily from increased storage asset opportunities realized in a high and increasingly volatile natural gas commodity price environment. Distribution operations net operating revenues decreased $2.2 million due to decreased volumes. Distribution operations residential sales and transportation volumes decreased 840 MMcf from 2004 to 2005 due to decreased base load and lower customer use per degree day. These reductions resulted from increased customer conservation, more timely termination of non-paying customers in 2005 and other factors. Increased volumes as a result of colder weather partially offset these decreases in residential volumes, as heating degree days were 5,543 in 2005, which was 3% colder than the 5,360 heating degree days in 2004 although still warmer than normal. Distribution operations commercial and industrial volumes decreased 4,229 MMcf from 2004 to 2005 primarily due to a reduction in industrial throughput to two major steel-making customers. These high volume industrial sales have very low unit margins and did not significantly impact total net operating revenues. Pipeline operations net operating revenues decreased $1.3 million from 2004 to 2005 primarily due to a $3.8 million loss on fuel and retention in excess of the current rates. This loss was partially offset by increased revenues earned in loaning and parking services. These services are contracted on an as-available basis, as opposed to long-term firm storage contracts. This flexibility allows customers, including the Company s marketing affiliate, to take advantage of the pipeline s available storage to secure future supply at favorable prices. These services were heavily subscribed in 2005, as higher volatility in natural gas prices provided substantial value for storage options.

Operating expenses totaled $155.1 million for 2005 compared to $134.6 million for 2004. Operating expenses for 2005 included $16.0 million in charges related to the termination and settlement of certain defined benefit pension plans and a $3.8 million loss related to the impairment of certain leased offices, furniture and equipment in connection with the Company s relocation into its new, consolidated office space. Excluding these items, operating expenses increased $0.7 million, which resulted from increases of $2.3 million in depreciation expense, $2.2 million in incentive compensation, $1.4 million in customer operations expenses and $1.1 million in employee benefit costs, largely offset by decreases of $4.7 million in bad debt expense and $1.4 million in insurance costs. The increased depreciation expense is a result of increased capital spending in Equitable Utilities over the past two years and is primarily related to computer hardware and software, distribution mainline and service line replacements and the installation of automated meter reading devices. The improvements in bad debt expense are a result of the more timely termination of non-paying customers, a full year impact of a $0.30 per Mcf regulatory surcharge instituted in April 2004, improved efforts to obtain alternative funding for low income customers and other improvements in the collections process. These improvements were offset somewhat in the fourth quarter of 2005 by high commodity rates and cold weather, which resulted in increased provisions for bad debt in that period compared to the prior year.

See Capital Resources and Liquidity section for discussion of Equitable Utilities capital expenditures during 2006, 2005 and 2004.

Outlook

Equitable Utilities business strategy is focused on operational excellence. Success in this strategy depends upon efficiently and effectively operating its gas distribution assets to optimize a return on assets. Going forward, Equitable Utilities expects to grow its gas distribution business selectively by acquisition. It also expects to continue to develop a portfolio of closely related unregulated businesses. Key elements of Equitable Utilities strategy include:

- **Enhancing the value and growth potential of the regulated utility operations.** Equitable Utilities will seek to enhance the value and growth of its existing utility assets by managing its capital spending effectively; establishing a reputation for excellent customer service; continuing to leverage technology; working to achieve authorized returns in each jurisdiction and, in those jurisdictions where it has performance-based rates, sharing the benefits with its customers; and maintaining earnings and rate stability through regulatory arrangements that fairly balance the interests of customers and shareholders.

- **Closing and integrating the acquisition of The Peoples Natural Gas Company and Hope Gas, Inc.** Equitable Utilities is focused on obtaining the required regulatory approvals to close the acquisition of The Peoples Natural Gas Company and Hope Gas, Inc. Transition planning activities have commenced at Equitable Utilities to plan for the integration of The Peoples Natural Gas Company and Hope Gas, Inc. into Equitable Resources, with $12.3 million of expenses incurred through December 31, 2006. The assets to be acquired will increase: customers in the distribution operations by 475,000 or 173%; total storage capacity by 33 Bcf or 60%, miles of gathering pipelines by 936 miles; gathered volumes by 40%; and miles of high pressure transmission by 466 miles or 42%. Based on the work completed to date, the Company expects that the conversion activities will continue at a similar monthly rate through June 2007 and increase Equitable Utilities operating expenses in the first and second quarter of 2007 in anticipation of closing the transaction.

- **Selectively expanding Equitable Utilities natural gas storage and gathering operations.** Equitable Utilities will endeavor to continue to expand its natural gas storage and gathering businesses to provide disciplined incremental earnings growth for shareholders. Equitable Utilities also intends to continue to invest capital in its underground storage business to expand its operational capabilities by increasing storage deliverability, thereby providing an opportunity to capture increased value from the volatility in natural gas prices. Equitable Utilities intends to grow its asset management business by providing its customers with gas supply, storage and asset management options; capturing value from increased natural gas gathering margins; providing producers with access to markets for their increased production; and arbitraging pipeline and storage assets across various gas markets and time horizons. Capturing this value from Equitable Utilities storage assets may increase the volatility of reported earnings from this business. Equitable Utilities will continue to focus on marketing energy to customers from its own assets; controlling costs; and managing its portfolio with smart business decisions while looking for additional opportunities to provide economical storage services in the regions in which the Company operates.

Equitable Supply

Overview

Equitable Supply s sales revenues for 2006 were essentially flat in comparison with 2005 revenues. Sales volumes increased more than 5% from 2005 excluding volumes from properties sold during 2005, primarily as a result of increased production from the 2006 and 2005 drilling programs partially offset by the normal production decline in the Company s existing wells. Equitable Supply drilled 560 gross operated wells in 2006 compared to 420 gross operated wells in 2005, a 33% increase. The 560 operated wells included 5 horizontal wells and 16 wells drilled as part of a coal bed methane infill pilot.

The positive results experienced from the increased sales volumes were more than offset by a 7% decline in the average well-head sales price, due primarily to decreased market prices. The average NYMEX price decreased 16% in 2006 from the abnormally high price levels in 2005, negatively impacting revenues from sales of unhedged volumes.

Operating expenses at Equitable Supply increased 12% primarily due to certain non-recurring charges for royalty disputes, bad debt expenses and pension and other postretirement plans, as well as higher DD&A and gathering and compression expenses resulting from increased drilling and infrastructure investments, as the Company continues to expand its development and midstream activities in the Appalachian Basin.

29

Results of Operations

	Years Ended December 31,				
	2006	**2005**	**% change 2006 - 2005**	**2004**	**% change 2005 - 2004**
OPERATIONAL DATA					
Capital expenditures (thousands) (a)	$ 336,748	$ 264,095	27.5	$ 141,661	86.4
Production:					
Total sales volumes (MMcfe)	76,156	73,909	3.0	67,731	9.1
Average (well-head) sales price ($/Mcfe)	$ 4.83	$ 5.17	(6.6)	$ 4.46	15.9
Company usage, line loss (MMcfe)	5,215	4,897	6.5	5,090	(3.8)
Natural gas inventory usage, net (MMcfe)		(51)	100.0	(61)	(16.4)
Natural gas and oil production (MMcfe) (b)	81,371	78,755	3.3	72,760	8.2
Lease operating expenses (LOE), excluding production taxes ($/Mcfe)	$ 0.30	$ 0.29	3.4	$ 0.26	11.5
Production taxes ($/Mcfe)	$ 0.48	$ 0.49	(2.0)	$ 0.34	44.1
Production depletion ($/Mcfe)	$ 0.62	$ 0.59	5.1	$ 0.54	9.3
Gathering:					
Gathered volumes (MMcfe)	108,592	121,044	(10.3)	127,339	(4.9)
Average gathering fee ($/Mcfe)	$ 1.02	$ 0.82	24.4	$ 0.58	41.4
Gathering and compression expense ($/Mcfe)	$ 0.42	$ 0.31	35.5	$ 0.28	10.7
Gathering and compression depreciation ($/Mcfe)	$ 0.14	$ 0.12	16.7	$ 0.11	9.1
(in thousands)					
Production operating income	$ 231,849	$ 260,931	(11.1)	$ 212,657	22.7
Gathering operating income	37,315	32,650	14.3	14,712	121.9
Total operating income	$ 269,164	$ 293,581	(8.3)	$ 227,369	29.1
Production depletion	$ 50,330	$ 46,750	7.7	$ 39,100	19.6
Gathering and compression depreciation	15,411	14,312	7.7	13,441	6.5
Other DD&A	4,759	3,835	24.1	3,295	16.4
Total DD&A	$ 70,500	$ 64,897	8.6	$ 55,836	16.2

	Years Ended December 31,				
	2006	2005	% change 2006 - 2005	2004	% change 2005 - 2004
FINANCIAL DATA (thousands)					
Production revenues	$ 377,626	$ 390,290	(3.2)	$ 315,986	23.5
Gathering revenues (c)	110,945	98,901	12.2	74,442	32.9
Total operating revenues	488,571	489,191	(0.1)	390,428	25.3
Operating expenses:					
LOE, excluding production taxes	24,620	23,195	6.1	18,685	24.1
Production taxes (d)	38,653	38,288	1.0	24,589	55.7
Gathering and compression (O&M)	45,860	38,101	20.4	35,494	7.3
SG&A	39,774	30,610	29.9	28,455	7.6
Impairment charges		519	(100.0)		100.0
DD&A	70,500	64,897	8.6	55,836	16.2
Total operating expenses	219,407	195,610	12.2	163,059	20.0
Operating income	$ 269,164	$ 293,581	(8.3)	$ 227,369	29.1
Equity in earnings of nonconsolidated investments	$ 129	$ 493	(73.8)	$ 688	(28.3)
Other income, net	$	$		$ 576	(100.0)

(a) 2005 capital expenditures include $57.5 million for the acquisition of the limited partnership interest in Eastern Seven Partners, L.P. (ESP).

(b) Natural gas and oil production represents the Company s interest in gas and oil production measured at the well-head. It is equal to the sum of total sales volumes, Company usage, line loss, and natural gas inventory usage, net.

(c) Revenues associated with the use of pipelines and other equipment to collect, process and deliver natural gas from the field to the trunk or main transmission line. Many contracts are for a blended gas commodity and gathering price, in which case the Company utilizes standard measures in order to split the price into its two components.

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

Fiscal Year Ended December 31, 2006 vs. December 31, 2005

Equitable Supply s operating income totaled $269.2 million for 2006 compared to $293.6 million for 2005, a decrease of $24.4 million between years. Production operating income decreased $29.1 million primarily due to a decrease in well-head sales price and an increase in production operating expenses, partially offset by increased sales volumes. Gathering operating income increased $4.7 million due to an increase in the average gathering fee, partially offset by decreased gathered volumes and increased gathering operating expenses.

Total operating revenues were $488.6 million for 2006 compared to $489.2 million for 2005. The $0.6 million decrease in net operating revenues was primarily due to a 7% per Mcfe decrease in the average well-head sales price, partially offset by a 3% increase in production total sales volumes and a 12% increase in gathering revenues. The $0.34 per Mcfe decrease in the average well-head sales price was mainly attributable to decreased market prices on unhedged volumes and increased gathering charges, partially offset by the absence of a 2005

31

negative price adjustment. The 2005 adjustment was principally due to the Company s conclusion that the well-head sales price allocated to a third party s working interest gas in previous periods may have been lower than the Company was obligated to pay.The 3% increase in production total sales volumes was primarily the result of the 2006 and 2005 drilling programs, partially offset by the sale of certain non-core gas properties in 2005 and the normal production decline in the Company s wells. The 12% increase in gathering revenues was attributable to a 24% increase in the average gathering fee, partially offset by a 10% decline in gathered volumes. The increase in average gathering fee is reflective of the Company s commitment to an increased infrastructure capital program, along with higher gas prices and related operating cost increases. The average gathering fee was also positively impacted by the transfer of certain regulated gathering facilities to Equitable Utilities. The decrease in gathered volumes in 2006 was primarily due to the transfer of gathering facilities to Equitable Utilities, the sale of gathering assets in 2005 and third-party customer volume shut-ins caused by maintenance projects on interstate pipelines. These factors were partially offset by increased gathered volumes for Company production in 2006.

Operating expenses totaled $219.4 million for 2006 compared to $195.6 million for 2005. The $23.8 million increase in operating expenses was due to increases of $9.2 million in SG&A, $7.8 million in gathering and compression, $5.6 million in DD&A, $1.4 million in LOE, and $0.4 million in production taxes, partially offset by a $0.5 million impairment charge in 2005 related to the Company s office consolidation. The increase in SG&A was the result of reserves established in connection with West Virginia royalty disputes and bad debt expenses. The increase in gathering and compression was primarily due to pension and other postretirement benefits charges for an early retirement program totaling $3.3 million, increased compressor station operation and repair costs, including electricity on newly installed compressors, increased property taxes and increased field labor and related employment costs. These factors were partially offset by the transfer of gathering facilities to Equitable Utilities and the sale of gathering assets in 2005. The increase in DD&A was due to a $0.03 per Mcf increase in the unit depletion rate ($2.0 million), increased depreciation on a higher asset base ($2.0 million) and increased produced volumes ($1.6 million). The increase in the unit depletion rate was primarily due to the net development capital additions in 2005 on a relatively consistent proved reserve base. The increase in LOE was primarily due to increased direct well expenses and well and location repairs and maintenance, partially offset by the sale of gas properties in 2005. The increase in production taxes was due to increased property taxes ($2.4 million), partially offset by decreased severance taxes ($2.0 million). The increase in property taxes was a direct result of increased prices and sales volumes in prior years, as property taxes in several of the taxing jurisdictions where the Company s wells are located are calculated based on historical gas commodity prices and sales volumes. The decrease in severance taxes (a production tax directly imposed on the value of gas extracted) was primarily due to lower gas commodity prices in the various taxing jurisdictions that impose such taxes. The impairment charges in 2005 were related to the Company s relocation of its corporate headquarters and other operations of its new consolidated office space.

Fiscal Year Ended December 31, 2005 vs. December 31, 2004

Equitable Supply s operating income totaled $293.6 million for 2005 compared to $227.4 million for 2004, an increase of $66.2 million between years. Production operating income increased $48.2 million primarily due to an increase in well-head sales price and an increase in sales volumes, partially offset by increased production operating expenses. Gathering operating income increased $18.0 million due to an increase in the average gathering fee, partially offset by decreased gathered volumes and increased gathering operating expenses.

Total operating revenues were $489.2 million for 2005 compared to $390.4 million for 2004. The $98.8 million increase in net operating revenues was primarily due to a 16% increase in the average well-head sales price, a 9% increase in production total sales volumes and a 33% increase in gathering revenues. The $0.71 per Mcfe increase in the average well-head sales price was mainly attributable to increased market prices on unhedged volumes partially offset by the adjustment related to a third party s working interest gas as previously discussed. The 9% increase in production total sales volumes was primarily the result of the purchase of ESP, partially offset by the sale of gas properties. The 33% increase in revenues from gathering fees was attributable to a 41% increase in the average gathering fee, partially offset by a 5% decline in gathered volumes. The increase in average gathering fee is reflective of the Company s commitment to an increased infrastructure capital program, along with higher gas prices and related operating cost increases. The decrease in gathered volumes in 2005 was primarily due to the sale of gathering assets and third-party customer volume shut-ins caused by maintenance projects on interstate pipelines. These factors were partially offset by increased gathered volumes for Company production in 2005. These increases in production and gathering revenues were partially offset by the recognition of a gain of $2.7 million in 2004 that resulted from the renegotiation of a processing agreement.

Operating expenses totaled $195.6 million for 2005 compared to $163.1 million for 2004. A significant reason for this $32.5 million increase was due to additional costs of $15.0 million resulting from the purchase of ESP. The $15.0 million of costs were primarily related to DD&A ($4.7 million), production taxes ($4.6 million), lease operating expenses ($3.7 million) and gathering expenses ($2.0 million). Excluding the ESP costs, the $17.5 million increase in operating expenses was due to increases of $9.1 million in production taxes, $4.4 million in DD&A, $2.1 million in SG&A, $0.8 million in LOE, $0.6 million in gathering expenses and $0.5 million in impairment charges related to the Company s office consolidation. The increase in production taxes was due to increased property taxes ($5.4 million) and severance taxes ($3.7 million). The increase in property taxes was a direct result of increased prices and sales volumes in prior years. The increase in severance taxes was primarily due to higher gas commodity prices and sales volumes in 2005 as compared to prior years.

The increase in DD&A excluding ESP was due to a $0.05 per Mcf increase in the unit depletion rate ($4.3 million) and increased depreciation on a higher asset base ($1.4 million), partially offset by lower depletion as a result of decreased volumes from the sale of gas properties ($1.3 million). The increase in the unit depletion rate was primarily due to the net development capital additions in 2005 and 2004. The increase in SG&A was the result of increased legal and professional fees and bad debt expenses. The increase in LOE was the result of the Company s strategy to focus on current infrastructure as well as increased costs from vendors due to higher gas prices. The increase in gathering expenses was primarily attributable to increased electricity charges resulting from newly installed electric compressors, field labor and related employment costs and compressor station operation and repair costs. The gathering and compression increases are consistent with the Company s strategic decision to focus on improving gathering and compression and metering effectiveness. Such increases were partially offset by reductions in gathering expenses due to reduced gathered volumes.

Other income, net for 2004 was the result of a $6.1 million settlement received from a previously disputed insurance coverage claim, offset by a $5.5 million expense related to the Company s settlement of a prepaid forward contract in 2004.

See Capital Resources and Liquidity section for discussion of Equitable Supply s capital expenditures during 2006, 2005 and 2004.

Outlook

Equitable Supply s Appalachian Basin business strategy is focused on growing through expansion of its drilling program and gathering systems. The Company will continue to emphasize operational excellence, including cost control in all areas of its operations. Key elements of Equitable Supply s strategy include:

- **Expanding production through the drilling program.** Equitable Supply has a multi-year drilling program which includes increased drilling of conventional wells, down spacing coal bed methane wells, continuing its horizontal drilling efforts and selectively participating in non-operated wells developed on acreage held by the Company. These efforts will enable the Company to continue the growth of its production business. Equitable Supply intends to drill 650 gross operated wells in 2007, including at least 25 horizontal wells, a 16% increase over the 560 gross operated wells drilled in 2006. Through testing a variety of horizontal drilling techniques, the Company expects to better understand reservoir response and the economic viability of reserve development through horizontal drilling. Similarly, through the ongoing infill pilot, the Company will evaluate the economic viability of accelerating production by down spacing coal bed methane wells**.** Equitable Supply believes that its 772 Bcfe of proved undeveloped reserves will be developed within a reasonable time period (currently estimated to be five years) because Equitable Supply (i) completed substantially all of the wells it drilled in the last three years and (ii) developed proved undeveloped reserves of 60 Bcfe and 70 Bcfe during 2006 and 2005, respectively. Equitable Supply s plans include developing similar levels of proved undeveloped reserves going forward.

• **Investing in midstream gathering and processing in the Appalachian Basin.** Infrastructure to support the Company s increased drilling, to mitigate curtailments on and increase flexibility and reliability of gathering systems and to move gas from wellhead to market presents an acute need but also a significant opportunity for the Company.

• Through its Equitrans affiliate, the Company is constructing the Big Sandy Pipeline, which will provide for a significant increase in midstream throughput capacity. The Company is also planning an upgrade to the Company-operated hydrocarbon processing plant in Langley, Kentucky for completion in early 2008. The projects are projected to cost an aggregate of $191 million.

• The Company plans to expand its gathering systems by approximately 200 miles of gathering line and approximately 25,000 horsepower of compression in 2007. Many of the existing gathering lines will be increased in size to handle these additional volumes and new gathering lines will be constructed to expanded drilling areas. The Company plans to build new compression stations as well as expand existing stations in order to transport gas to sales points on interstate pipelines.

• The Company is also evaluating several other processing, gathering line and compression expansion opportunities in Appalachia and expects to invest in additional projects in 2007 and beyond.

These efforts will assist the Company to move not only its gas, but also third party producer gas, from wellhead to market.

Other Income Statement Items

	Years Ended December 31, 2006 (Thousands)	2005	2004
Income (loss) from discontinued operations	$ 4,261	$ 1,481	$ (18,936)
Gain on sale of available-for-sale securities, net		110,280	3,024
Other income, net		1,195	3,692
Gain on exchange of Westport for Kerr-McGee shares			217,212
Charitable foundation contribution			(18,226)

As noted in Item 1, the Company s NORESCO business is classified as discontinued operations due to the sale of the NORESCO domestic business in 2005 and sale of the Company s remaining international investment in early 2006. Income (loss) from discontinued operations for 2006 included a tax benefit of $3.2 million due to a reduced tax liability on the sale and after-tax income of $1.1 million resulting from the Company s reassessment of its remaining obligations for costs incurred related to the sale. Income (loss) from discontinued operations for 2004 included approximately $23.9 million of after-tax impairments on international investments and charges for related reserves, while income (loss) from discontinued operations for 2005 included the reversal of approximately $7.8 million of these reserves (after tax) due to improved business conditions in the related international markets, as well as a $6.4 million tax benefit from the reorganization of the Company s international assets in 2005. These increases in 2005 as compared to 2004 were partially offset by $18.7 million in after-tax charges recorded in 2005, related to the recording of $13.7 million of income taxes on the sale and other costs incurred as a result of the sale transaction.

During 2005, the Company sold its remaining 7.0 million Kerr-McGee shares resulting in pre-tax gains net of collar termination costs totaling $110.3 million. During 2004, the Company sold 0.8 million Kerr-McGee shares, resulting in a pre-tax gain of $3.0 million.

Other income, net includes pre-tax dividend income relating to the Kerr-McGee shares held by the Company of $1.2 million and $3.1 million for 2005 and 2004, respectively.

As a result of the 2004 merger between Westport and Kerr-McGee, the Company recognized a gain of $217.2 million on the exchange of its Westport shares for Kerr-McGee shares. See Note 9 to the Company s Consolidated Financial Statements for further information on this transaction.

In 2004, the Company contributed approximately 0.4 million Kerr-McGee shares to Equitable Resources Foundation, Inc., resulting in the Company recording a charitable foundation contribution expense of $18.2 million during 2004. See Note 9 to the Company s Consolidated Financial Statements for further information on this transaction.

Interest Expense

	Years Ended December 31, 2006 (Thousands)	2005	2004
Interest expense	$ 47,052	$ 44,437	$ 42,520

Interest expense increased by $2.7 million from 2005 to 2006 primarily due to a full year of interest expense in 2006 from the issuance of $150 million of notes with a stated interest rate of 5% on September 30, 2005 and an increase in the average annual short-term debt interest rate, partially offset by lower average short-term debt during 2006.

Interest expense increased by $1.9 million from 2004 to 2005 primarily due to the issuance of $150 million of notes with a stated interest rate of 5% on September 30, 2005 and an increase in the average annual short-term debt interest rate. These increases were partially offset by the maturity of $10 million of medium-term notes during 2005.

Average annual interest rates on the Company s short-term debt were 4.6%, 3.5%, and 1.7% for 2006, 2005 and 2004, respectively.

Capital Resources and Liquidity

Operating Activities

Cash flows provided by operating activities totaled $619.3 million for 2006 as compared to $312.0 million of cash flows used in operating activities for 2005, a net increase of $931.3 million in cash flows provided by operating activities between years. The increase in cash flows provided by operating activities was attributable to the following:

- a $598.7 million net reduction in cash required for margin deposit requirements on the Company s natural gas hedge agreements, primarily due to significantly higher than normal gas prices in 2005 which resulted in increased deposit remittances in that year;

- a decrease in tax payments to $58.6 million in 2006 from $251.5 million in 2005, primarily due to taxes paid in 2005 related to the sale of the Company s Kerr-McGee shares, the sale of the NORESCO discontinued operations and the sale of non-core gas properties for significant taxable gains, all in 2005;

- a decrease in accounts receivable of $63.5 million in 2006 compared to an increase of $78.0 million in 2005, primarily due to decreased natural gas prices during 2006 as compared to significant increases in prices in 2005;

- a decrease in inventory of $20.8 million during 2006 as compared to an increase of $85.3 million in 2005, primarily due to increased natural gas prices on volumes stored in 2005 as well as decreased prices in 2006;

35

partially offset by:

- a decrease in accounts payable of $29.3 million in 2006 compared to an increase of $71.5 million in 2005, primarily due to decreased natural gas prices during 2006 as compared to significant increases in prices in 2005;

- a large reduction in other current liabilities during 2006, as significant amounts were outstanding at December 31, 2005 for which payment was remitted shortly after the 2005 year-end.

Cash flows used in operating activities totaled $312.0 million for 2005 as compared to $180.0 million of cash flows provided by operating activities for 2004, a net increase of $492.0 in cash flows used in operating activities between years. The increase in cash flows used in operating activities was attributable to the following:

- an increase in margin deposit requirements to $317.8 million as of December 31, 2005, from $36.9 million as of December 31, 2004, primarily resulting from increased natural gas prices during 2005;

- an increase in tax payments to $251.5 million in 2005 compared to $23.0 million in 2004 as described above;

- an increase in inventory to $289.9 million as of December 31, 2005, from $204.6 million as of December 31, 2004, primarily due to increased natural gas prices on volumes stored in 2005 compared to 2004;

partially offset by:

- an increase in accounts payable to $242.6 million as of December 31, 2005, from $171.2 million as of December 31, 2004, largely due to increased operating costs resulting from increased drilling activity and higher natural gas prices.

Investing Activities

Cash flows used in investing activities totaled $407.7 million for 2006 as compared to $347.7 million of cash flows provided by investing activities for 2005, a net increase of $755.4 million in cash flows used in investing activities between years. The increase in cash flows used in investing activities was attributable to the following:

- net proceeds of $460.5 million received from the sale of approximately 7.0 million shares of Kerr-McGee Corporation common stock in 2005;

- proceeds of $142.0 million from the sale of certain non-core gas properties and associated gathering assets in 2005;

- an increase in capital expenditures to $404.5 million in 2006 from $275.8 million in 2005. See discussion of capital expenditures below;

- proceeds of $80.0 million from the sale of the domestic operations of the Company s NORESCO business segment in 2005;

partially offset by:

- the Company s acquisition of the 99% limited partnership interest in ESP for $57.5 million in 2005.

Cash flows provided by investing activities totaled $347.7 million for 2005 as compared to $158.5 million of cash flows used in investing activities for 2004, a net increase of $506.2 million in cash flows provided by investing activities between years. The increase in cash flows provided by investing activities was attributable to the following:

- a $417.6 million year-over-year increase in net proceeds received from the sale of shares of Kerr-McGee;
- proceeds of $142.0 million from the sale of properties in 2005;
- proceeds of $80.0 million from the sale of NORESCO in 2005;

partially offset by:

- an increase in capital expenditures to $333.3 million in 2005 from $201.8 million in 2004. See discussion of capital expenditures below.

Capital Commitments and Expenditures

The Company forecasts $588 million of capital commitments for 2007. This forecast includes $237 million for well development, $256 million for Supply infrastructure, $92 million for Equitable Utilities and $3 million for Headquarters. A portion of these capital commitments is not expected to impact cash flow until 2008 and beyond.

Capital Expenditures

	2007 Forecast		2006 Actual	2005 Actual	2004 Actual
Well development (primarily drilling)	$ 231 million		$ 200 million	$131 million plus $58 million for the purchase of ESP	$ 92 million
Supply infrastructure	$ 396 million		$ 137 million	$ 75 million	$ 50 million
Equitable Utilities	$ 82 million		$ 65 million	$ 61 million	$ 56 million
Headquarters	$ 3 million		$ 3 million	$ 8 million	$ 4 million
Total*	$ 712 million	*	$ 405 million	$ 333 million	$ 202 million

* The 2007 capital expenditures do not include amounts related to the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc. The 2007 capital expenditures include 2006 capital commitments totaling $361 million, including $257 million for Supply infrastructure, $92 million for well development, and $12 million for Equitable Utilities.

Capital expenditures for well development and Supply infrastructure increased in 2006 as compared to 2005 primarily due to an increased drilling and development plan in 2006, capital expended for construction of the Big Sandy Pipeline and other throughput optimization projects. Capital expenditures for well development and Supply infrastructure increased in 2005 as compared to 2004 primarily due to an increased drilling and development plan in 2005.

Capital expenditures for Equitable Utilities increased in 2006 as compared to 2005 primarily due to increased transmission pipeline replacement associated with pipeline integrity under The Pipeline Safety Improvement Act of 2002 and increased gathering infrastructure expenditures. Capital expenditures for Equitable Utilities increased in 2005 as compared to 2004 due to the installation of electronic meter reading technology on meters in the distribution operations, a project that was substantially completed in the third quarter of 2006.

The Company s capital expenditures forecasted for 2007 represent a significant increase over capital expenditures in 2006. The $231 million targeted for well development in 2007 represents a $31 million increase over 2006 which is attributable to an expanded drilling program. The $396 million forecasted for 2007 Supply infrastructure includes further expansions in infrastructure to support the Company s current and future drilling plans as well as expenditures for the Big Sandy Pipeline and Langley plant projects. The $82 million forecasted for Equitable Utilities includes $77 million for infrastructure improvements and $5 million for new business development. The infrastructure improvements include improvements to existing distribution lines, an increase in transmission pipeline replacement and additional investment in gathering system improvements and extensions. The new business capital is planned for extensions of existing infrastructure into adjacent geographic areas.

The Company expects to finance its capital expenditures with cash generated from operations and with short-term debt. See discussion in the Short-term Borrowings section below regarding the financing capacity of the Company.

Financing Activities

Cash flows used in financing activities totaled $286.5 million for 2006 as compared to $39.2 million of cash flows provided by financing activities for 2005, a net increase of $325.7 million in cash flows used in financing activities between years. The increase in cash flows used in financing activities was attributable largely to the following:

- a $229.3 million decrease in amounts borrowed under short-term loans in 2006 compared to a $69.8 million increase in short-term borrowings in 2005. The decrease in short-term borrowings in 2006 was primarily the result of decreased requirements for funding margin deposits as previously discussed;

- proceeds in 2005 from the September 2005 issuance of $150.0 million of notes with a stated interest rate of 5% and a maturity date of October 1, 2015;

partially offset by:

- no repurchases of shares of the Company s outstanding common stock under the Company s share repurchase program during 2006 in anticipation of the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc., compared to repurchases of $122.3 million of common stock in 2005.

Cash flows provided by financing activities totaled $39.2 million for 2005 as compared to $55.8 million of cash flows used in financing activities for 2004, a net increase of $95.0 million in cash flows provided by financing activities between years. The increase in cash flows provided by financing activities from 2004 to 2005 was attributable largely to the following:

- proceeds of $150.0 million from the issuance of notes in September 2005;

partially offset by:

- less of an increase in amounts borrowed under short-term loans in 2005 as compared to 2004.

The Company believes that cash generated from operations, amounts available under its credit facilities and amounts which the Company could obtain in the debt and equity markets given its financial position, are more than adequate to meet the Company s reasonably foreseeable liquidity requirements. The Company anticipates financing its capital expenditures and the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc. through a combination of debt, equity, and asset sales.

Short-term Borrowings

Cash required for operations is affected primarily by the seasonal nature of the Company s natural gas distribution operations and the volatility of oil and natural gas commodity prices. The Company s $1.5 billion, five-year revolving credit agreement may be used for working capital, capital expenditures, share repurchases and other purposes including support of the Company s commercial paper program. Historically, short-term borrowings under the commercial paper program have been used mainly to support working capital requirements during the summer months and are repaid as natural gas is sold during the heating season. Due to decreased natural gas prices and increased margin deposit thresholds with financial institutions during 2006 and resulting decreases in the Company s net liability position under its natural gas swap agreements, the Company borrowed decreased amounts through its commercial paper program to fund its interest-bearing margin deposits under its natural gas hedge agreements. The amount of commercial paper outstanding at December 31, 2006 was $136.0 million. Interest rates on these short-term loans averaged 4.6% during 2006.

Security Ratings* and *Financing Triggers

The table below reflects the current credit ratings for the outstanding debt instruments of the Company. Changes in credit ratings may affect the Company s cost of short-term and long-term debt and its access to the credit markets.

Rating Service	**Unsecured Medium-Term Notes**	**Commercial Paper**
Moody s Investors Service	A-2	P-1
Standard & Poor s Ratings Services	A -	A-2

On March 2, 2006, Standard & Poor s Ratings Services placed the Company s short and long-term credit ratings on CreditWatch with negative implications and Moody s Investors Service placed the ratings under review for possible downgrade. These actions resulted from the Company s announcement that it had entered into a definitive agreement to acquire The Peoples Natural Gas Company and Hope Gas, Inc., subject to anti-trust and regulatory approvals. The final ratings outcomes are expected to be determined after the acquisition financing plan has been reviewed by the ratings agencies and the regulatory approval process is near completion.

The Company s credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. The Company cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a credit rating agency if, in its judgment, circumstances so warrant. If the credit rating agencies downgrade the Company s ratings, particularly below investment grade, it may significantly limit the Company s access to the commercial paper market and borrowing costs would increase. In addition, the Company would likely be required to pay a higher interest rate in future financings, incur increased margin deposit requirements with respect to its hedging instruments, and the potential pool of investors and funding sources would decrease.

The Company s credit ratings 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 credit rating, the higher the level of fees and interest rate. As of December 31, 2006, the Company had no outstanding borrowings against these lines of credit. The Company pays facility fees to maintain credit availability.

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 important 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 accumulated other comprehensive income (loss). During an acquisition period, which is defined as the period beginning with the funding of the purchase price for the stock of The Peoples Natural Gas Company and Hope Gas, Inc. and ending on the first fiscal quarter end at least 365 days after the funding of such purchase price, the covenant is relaxed from 65% to 70%. As of December 31, 2006, the Company is in compliance with all existing debt provisions and covenants.

Commodity Risk Management

The Company s overall objective in its hedging program is to protect earnings from undue exposure to the risk of changing commodity prices. The Company s risk management program includes 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 and for trading purposes. The preponderance of derivative commodity instruments currently utilized by the Company are fixed price swaps or collars.

During 2006, the Company increased its hedge position for 2007 through 2013. As a result, the approximate volumes and prices of the Company s total hedge position for 2007 through 2009 are:

	2007		2008		2009	
Swaps						
Total Volume (Bcf)	56		54		38	
Average Price per Mcf (NYMEX)*	$	4.74	$	4.64	$	5.90
Collars						
Total Volume (Bcf)	10		10		10	
Average Floor Price per Mcf (NYMEX)*	$	7.61	$	7.61	$	7.61
Average Cap Price per Mcf (NYMEX)*	$	11.27	$	11.27	$	11.27

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

The Company s current hedged position provides price protection for a substantial portion of expected equity production for the years 2007 through 2009 and a significant portion of expected equity production for the years 2010 through 2013. The Company s exposure to a $0.10 change in average NYMEX natural gas price is approximately $0.01 per diluted share for 2007 and ranges from $0.01 to $0.03 per diluted share per year for 2008 and 2009. 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. See Note 3 to the Company s Consolidated Financial Statements for further discussion.

Investment Securities

The Company s available-for-sale investments as of December 31, 2006 and 2005 consist of approximately $31.3 million and $25.2 million, respectively, of equity securities that are intended to fund certain liabilities for which the Company is self-insured. These investments are recorded at fair market value. During 2005, the Company sold all of its remaining 7.0 million shares of Kerr-McGee in various transactions for total net pre-tax proceeds of $460.5 million and a total pre-tax gain of $110.3 million, net of $95.8 million in costs associated with the termination of the three related variable share forward transactions entered into in June 2004 subsequent to the Westport/Kerr-McGee merger.

Other Items

Off-Balance Sheet Arrangements

The Company has a non-equity interest in a variable interest entity, Appalachian NPI, LLC (ANPI), in which Equitable was not deemed to be the primary beneficiary. As of December 31, 2006, ANPI had $214 million of total assets and $336 million of total liabilities (including $137 million of long-term debt, including current maturities), excluding minority interest.

The Company provides a liquidity reserve guarantee to ANPI, which is subject to certain restrictions and limitations, and is secured by the fair market value of the assets purchased by the Appalachian Natural Gas Trust (ANGT). The Company received a market-based fee for the issuance of the reserve guarantee. As of December 31, 2006, the maximum potential amount of future payments the Company could be required to make under the liquidity reserve guarantee is estimated to be approximately $50 million. The Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN 45 and has not been modified subsequent to issuance.

The Company has entered into an agreement with ANGT to provide gathering and operating services to deliver ANGT s gas to market. In addition, the Company receives a marketing fee for the sale of gas based on the net revenue for gas delivered. The revenue earned from these fees totaled approximately $16.8 million for 2006.

In connection with the sale of its NORESCO domestic business in 2005, the Company agreed to maintain certain guarantees which benefit NORESCO. These guarantees, the majority of which predate the sale of NORESCO, became off-balance sheet arrangements upon the closing of the sale of NORESCO. These arrangements include guarantees of NORESCO s obligations to the purchasers of certain of NORESCO s contract receivables and agreements to maintain guarantees supporting NORESCO s obligations under certain customer contracts. In addition, NORESCO and the purchaser agreed that NORESCO would fully perform its obligations under each underlying agreement and that the purchaser or NORESCO would reimburse the Company for losses under the guarantees. The purchaser s obligations to reimburse the Company are capped at $6 million. The Company determined that the likelihood the Company will be required to perform on these arrangements is remote, and as such, the Company has not recorded any liabilities in its Consolidated Balance Sheets related to these guarantees. The total maximum potential obligation under these arrangements is estimated to be approximately $484 million as of December 31, 2006, and decreases over time as the guarantees expire or the underlying obligations are fulfilled by NORESCO.

See Note 20 to the Consolidated Financial Statements for further discussion of the Company s guarantees.

Pension Plans

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize a benefit plan s funded status in its statement of financial position, measure a benefit plan s assets and obligations as of the end of the employer s fiscal year and recognize the changes in the benefit plan s funded status in other comprehensive income in the year in which the changes occur. SFAS No. 158 s requirement to recognize the funded status of a benefit plan and the new disclosure requirements were effective for the year-ended December 31, 2006. See Footnote 13 for information regarding the adoption of SFAS No. 158 as of December 31, 2006.

Total pension expense recognized by the Company in 2006, 2005 and 2004, excluding special termination benefits, settlement losses and curtailment losses, totaled $0.1 million, $0.4 million and $0.4 million, respectively. The Company recognized special termination benefits, settlement losses and curtailment losses in 2006, 2005 and 2004 of $3.0 million, $18.4 million and $16.2 million, respectively. As a result of these costs, the Company s projected benefit obligation decreased by approximately $36.0 million.

During the fourth quarter of 2006, the Company recognized a settlement expense of approximately $2.7 million for an early retirement program.

During 2005, the Company settled its pension obligation with the United Steelworkers of America, Local Union 12050 representing 182 employees. As a result of this settlement, the Company recognized a settlement expense of $12.1 million during 2005. During the fourth quarter of 2005, the Company settled its pension obligation with certain non-represented employees. As a result of this settlement, the Company recognized a settlement expense of approximately $2.4 million in 2005.

Effective December 31, 2004, the Company settled the pension obligation of those non-represented employees (cash balance participants) whose benefits were frozen as of December 31, 2003. As a result of this settlement, the Company recognized settlement expense of $13.4 million in 2004.

The Company made cash contributions of approximately $1.8 million and $20.4 million to its pension plan during 2006 and 2005, respectively, as a result of the previously described settlements. The Company expects to make cash contributions of approximately $1.0 million to its pension plan during 2007. The Company was not required to, and consequently did not make any contribution to its pension plans during the year ended December 31, 2004.

Incentive Compensation

The Company adopted SFAS No. 123R on January 1, 2006, which results in the Company recognizing compensation cost for all forms of share-based payments to employees, including employee stock options, as an expense in its income statement. The Company previously applied APB No. 25 in accounting for its share-based compensation and consequently did not recognize any compensation cost for its stock option awards. The Company s estimate of compensation cost for stock options is based on the use of the Black-Scholes option-pricing model. The Black-Scholes model is considered a theoretical or probability model used to estimate the price an option would sell for in the market today. The Company does not represent that this method yields an exact value of what an unrelated third party (i.e., the market) would be willing to pay to acquire such options.

The Company adopted SFAS No. 123R using the modified prospective method, under which the Company recorded compensation expense for its unvested stock options beginning January 1, 2006. As such, the Company did not restate any prior period income statement amounts. In addition, the adoption of SFAS No. 123R did not result in any significant changes to the Company s method for valuing its stock options from that previously used for pro forma disclosures under SFAS No. 123.

The adoption of SFAS No. 123R did not have a significant impact on the Company s operating results for 2006, as the Company has shifted its compensation focus to the issuance of performance-based units and time-restricted stock awards for which it already recognized compensation expense under generally accepted accounting principles. Management and the Board of Directors believe that such an incentive compensation approach more closely aligns management s incentives with shareholder rewards than is the case with traditional stock options. No new stock options have been awarded since 2003; all stock options granted subsequent to 2003 have comprised options granted for reload rights associated with previously-awarded options.

The Company recorded approximately $1.0 million of compensation expense related to stock options in 2006, the majority of which related to stock option reloads which immediately vested under the terms of the related stock option award agreements. The majority of the Company s previously issued stock options were already vested at the time of adoption of SFAS No. 123R, and associated compensation expense yet to be recognized was insignificant. All stock options outstanding as of December 31, 2006 are fully vested, and as such, the Company does not anticipate incurring any additional compensation expense related to currently outstanding stock options.

Had compensation cost been determined based on the fair value at the grant date for prior periods stock option grants consistent with the methodology prescribed in SFAS No. 123R, net income would have been reduced by an estimated $1.5 million, or approximately $0.01 per diluted share, for 2005, and an estimated $4.2 million, or approximately $0.04 per diluted share, for 2004.

The Company recorded the following incentive compensation expense in continuing operations for the periods indicated below:

	Year Ended December 31,		
	2006	**2005**	**2004**
	(millions)		
Short-term incentive compensation expense	$ 16.7	$ 12.9	$ 13.7
Long-term incentive compensation expense	26.6	46.4	28.3
Total incentive compensation expense	$ 43.3	$ 59.3	$ 42.0

42

The long-term incentive compensation expenses are primarily associated with Executive Performance Incentive Programs (the Programs) that were instituted starting in 2002. The long-term incentive compensation expenses during 2006 were lower than during 2005 due to a greater number of unvested units outstanding during 2005 than during 2006, as there were two Programs in effect during 2005 and only one in 2006. The long-term incentive compensation expenses during 2005 were higher than during 2004 primarily due to a higher estimated share price for the Programs being expensed, as a result of the Company s share price appreciation, and a greater number of unvested units outstanding during 2005 than during 2004.

The Company currently estimates 2007 total incentive compensation expense of approximately $38 million.

Federal Legislation

During 2005, the Company completed its review of the American Jobs Creation Act of 2004 s impact on the Company s executive compensation plans, and the Compensation Committee of the Company s Board of Directors decided to end the Company s deferred compensation programs for employees. As a result, in 2005 the Company recorded $15.3 million in tax benefit disallowances under Section 162(m) of the IRC, primarily due to the impairment of previously recorded deferred tax assets related to the employee deferred compensation programs and the 2003 Executive Performance Incentive Program.

Rate Regulation

The Company s distribution operations and pipeline operations are subject to various forms of regulation as previously discussed. Accounting for the Company s regulated operations is performed in accordance with the provisions of SFAS No. 71. As described in Notes 1 and 10 to the Consolidated Financial Statements, regulatory assets and liabilities are recorded to reflect future collections or payments through the regulatory process. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of the deferred costs.

Schedule of Contractual Obligations

The following table details the future projected payments associated with the Company s contractual obligations as of December 31, 2006.

	Total (Thousands)	**2007**	**2008-2009**	**2010-2011**	**2012+**
Long-term debt	$ 763,500	$ 10,000	$ 4,300	$ 6,000	$ 743,200
Interest expense	497,705	44,663	88,526	87,860	276,656
Purchase obligations	211,716	41,126	68,670	57,203	44,717
Operating leases	55,964	6,767	10,273	6,108	32,816
Other long-term liabilities	87,152		87,152		
Total contractual obligations	$ 1,616,037	$ 102,556	$ 258,921	$ 157,171	$ 1,097,389

Included within the purchase obligations amount in the table above are annual commitments of approximately $37.8 million relating to the Company s natural gas distribution and production operations for demand charges under existing long-term contracts with pipeline suppliers for periods extending up to ten years. Approximately $26.4 million of these costs are believed to be recoverable in customer rates.

Operating leases are primarily entered into for various office locations and warehouse buildings, as well as a limited amount of equipment. The relocation of the Company to a new corporate headquarters in 2005 resulted in the early termination of several operating leases for facilities deemed to have no economic benefit to the Company. These obligations, which totaled $6.6 million as of December 31, 2006, are included in operating lease obligations detailed above.

The other long-term liabilities line represents the total estimated payout for the 2005 Executive Performance Incentive 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 this obligation.

Contingent Liabilities and Commitments

The various regulatory authorities that oversee Equitable s operations will, from time to time, make inquiries or investigations into the activities of the Company. It is the Company s policy to comply with applicable laws and cooperate when regulatory bodies make requests.

In June 2006, the West Virginia Supreme Court of Appeals issued a decision involving interpretation of certain types of oil and gas leases of an unrelated party, in which a class of royalty owners in the state of West Virginia filed a lawsuit claiming that the defendant in the case underpaid royalties by deducting certain post-production costs not permitted by such types of leases and not paying a fair value for the gas produced from the royalty owners leases. In January 2007, the jury in the aforementioned case returned a verdict in favor of the plaintiff royalty owners, awarding the plaintiffs significant compensatory and punitive damages for the alleged underpayment of royalties. While the defendant plans to appeal the verdict, this decision may ultimately impact other royalty interest rights in West Virginia. Claims have been brought against others in the oil and gas industry, including the Company. The actions against the Company are in the early stages of proceedings. The Company believes that the claims and facts decided in the unrelated lawsuit can be differentiated from those asserted against the Company. Nevertheless, the Company has reviewed its West Virginia royalty agreements and established a reserve it believes to be appropriate.

See Note 19 to the Consolidated Financial Statements for further discussion of the Company s contingent liabilities and commitments.

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 Equitable 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 and approved 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. There can be no assurance that actual results will not differ from those estimates.

Provision for Doubtful Accounts: The Company encounters risks associated with the collection of its accounts receivable. Equitable Gas s state regulated relationship with its customers is particularly complex. Equitable Gas records a monthly provision for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, Equitable Gas primarily utilizes a historical rate of accounts receivable write-offs as a percentage of total revenue. This historical rate is applied to the current revenues on a monthly basis and is updated periodically based on events that may change the rate, such as a significant increase or decrease in commodity prices or a significant change in the weather. Both of these items ultimately impact the customers ability to pay and the rates that are charged to the customers due to the pass-through of purchased gas costs to the customers. Management reviews the adequacy of the allowance on a quarterly basis using the assumptions that apply at that time.

The monthly provision for uncollectible accounts amounted to approximately 1% and 2% of residential sales for 2006 and 2005, respectively. Beginning in April 2004, the Company began collecting a regulatory surcharge in the amount of $0.30 per Mcfe of gas sold to residential customers to help recover the costs associated with providing gas service to low-income customers. This surcharge is credited to the reserve for uncollectible accounts and reduces the amount which would otherwise be recognized as bad debt expense. This surcharge totaled $5.5 million in 2006, $6.5 million in 2005, and $3.3 million in 2004. In addition, during 2004, Equitable Gas implemented a new customer information and billing system that has enabled the Company to better segment customer information in order to identify customers who may have difficulty paying. Also, under the Responsible Utility Customer Protection Act, Equitable Gas is permitted to send winter termination notices to customers whose household income exceeds 250% of the federal poverty level and to complete customer terminations without approval from the PA PUC. The Company took advantage of these winter terminations in an effort to reduce its uncollectible accounts receivable.

The Company believes that the accounting estimates related to the allowance for doubtful accounts are critical accounting estimates because the underlying assumptions used for the allowance can change from period to period and the changes in the allowance could potentially cause a material impact to the income statement and working capital. The actual weather, commodity prices and other internal and external economic conditions, such as the mix of the customer base between residential, commercial and industrial, may vary significantly from management s assumptions and may impact the ultimate collectibility of customer accounts. Additionally, the regulatory environment allows certain customers to enter into long-term payment arrangements, the ultimate collectibility of which is difficult to determine.

Executive Performance Incentive Programs: The Company treats its Executive Performance Incentive Programs as variable plans. The actual cost to be recorded for the 2005 Executive Performance Incentive Program (2005 Program) will not be known until the measurement date, which is December 31, 2008, requiring the Company to estimate the total expense to be recognized. The number of units to be paid out under the 2005 Program is dependent upon a combination of a level of total shareholder return relative to the performance of a peer group and the Company s average absolute return on capital during the four-year performance period. The Company reviews these assumptions on a quarterly basis and adjusts its accrual for the 2005 Program when changes in these assumptions result in a material change in the value of the ultimate payout. In the current period, the Company estimated that the performance measures would be met at 175% of the full value of the units for the 2005 Program and that the estimated end of 2008 share price would be $45.00.

45

The Company believes that the accounting estimate related to the 2005 Program is a critical accounting estimate because it is likely to change from period to period based on the market price of the Company s shares and the performance of the peer group. Additionally, the impact on net income of these changes could be material. Management s assumptions about future stock price and Company performance relative to the peer group requires significant judgment. Each company s inherent volatility combined with the volatility in commodity prices impact the ultimate amount of the payout and make it difficult to provide sensitivity metrics to demonstrate what impact a change in the Company s stock price will have on the estimate. However, assuming no change in the attainment of performance measures, a 10% increase in the Company s stock price assumptions for December 31, 2008 would result in an increase in 2007 compensation expense under the 2005 Program of approximately $6 million. A 10% decrease in the Company s stock price assumptions would result in a decrease in 2007 compensation expense of the same amount.

Income Taxes: The Company accounts for income taxes under the provisions of SFAS No. 109, which requires the recognition of 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. See Note 6 to the Company s Consolidated Financial Statements for further discussion.

The Company has recorded deferred tax assets principally resulting from mark-to-market hedging losses recorded in other comprehensive loss, deferred revenues and expenses and state net operating loss carryforwards. 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. The Company also recorded a $0.1 million charge in 2006 and a $15.3 million charge in 2005 related to compensation deferred and accrued under certain executive compensation plans, as it was determined that this compensation will not be deductible under Section 162(m) of the IRC. No other 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 assets. Any change in 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 believes that the accounting estimate related to income taxes is a critical accounting estimate because the Company must assess the likelihood that deferred tax assets will be recovered from future taxable income, and to the extent that it is believed to be 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. 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. Evidence used 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 liabilities and tax planning strategies available to the Company. To the extent that a valuation allowance is established or increased or decreased during a period, the Company must include an expense or benefit within tax expense in the income statement.

Contingencies: 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 recording of contingencies is guided by the principles of SFAS No. 5. The Company considers many factors in making these assessments, including history and specifics of each matter. Estimates are developed in consultation with legal counsel and are based upon an analysis of potential results.

The Company believes that the accounting estimate related to contingencies is a critical accounting estimate because 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, which can affect the operating results of the Company primarily through the Equitable Supply segment and the unregulated marketing group within the Equitable Utilities segment. 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 non-leveraged derivative commodity instruments that are placed with major financial institutions whose creditworthiness is continually monitored. The Company also enters into energy trading contracts to leverage its assets and limit its exposure to shifts in market prices. The Company s use of these 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

The following sensitivity analysis estimates the potential effect on fair value or future earnings from derivative commodity instruments due to a 10% increase and a 10% decrease in commodity prices.

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. The financial instruments currently utilized by the Company include 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 options and other contractual agreements in determining its commodity hedging strategy. Management monitors price and production levels on a continuous basis and will make adjustments to quantities hedged as warranted. In general, the Company s strategy is to hedge production at prices considered to be favorable to the Company. The Company attempts to take advantage of price fluctuations by hedging more aggressively when market prices move above historical averages and by taking more price risk when prices are significantly below these levels. The goal of these actions is to earn a return above the cost of capital and to lower the cost of capital by reducing cash flow volatility. To the extent that the Company has hedged its production at prices below the current market price, the Company is unable to benefit fully from increases in the price of natural gas.

With respect to the derivative commodity instruments held by the Company for purposes other than trading as of December 31, 2006, the Company hedged portions of expected equity production through 2013 by utilizing futures contracts, swap agreements and collar agreements covering approximately 310.1 Bcf of natural gas. See the Commodity Risk Management and Capital Resources and Liquidity sections of Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K for further discussion. For the sensitivity analysis set forth below, the Company determined the change in the fair value of the derivative commodity instruments using a model similar to its normal change in fair value as described in Note 1 to the consolidated financial statements. The Company assumed a 10% change in the price of natural gas from its levels at December 31, 2006. The price change was then applied to the derivative commodity instruments recorded on the Company s balance sheet, resulting in the change in fair value.

A hypothetical decrease of 10% in the market price of natural gas from the December 31, 2006 levels would increase the fair value of non-trading natural gas derivative instruments by approximately $222.3 million. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2006 levels would decrease the fair value of non-trading natural gas derivative instruments by approximately $221.8 million.

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 and its subsidiaries 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.

For derivative commodity instruments held for trading purposes, the Company engages in financial transactions also subject to policies that limit the net positions to specific value at risk limits. The financial instruments currently utilized by the Company for trading purposes include forward contracts and swap agreements.

A hypothetical increase or decrease of 10% in the market price of natural gas from the December 31, 2006 levels would not have a significant impact on the fair value of derivative commodity instruments held by the Company for trading purposes as of December 31, 2006.

Other Market Risks

The Company has variable rate short-term debt. As such, there is some exposure to future earnings due to changes in interest rates. A 100 basis point increase or decrease in interest rates would not have a significant impact on future earnings of the Company under its current capital structure. The Company maintains fixed rate long-term debt that is not subject to risk exposure from fluctuating interest rates.

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. The Company believes that NYMEX-traded futures contracts have minimal credit risk because futures exchanges are the counterparties. The Company manages the credit risk of the other derivative contracts by limiting dealings to those counterparties who meet the Company s criteria for credit and liquidity strength.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUTING FIRM

The Board of Directors and Shareholders

Equitable Resources, Inc.

We have audited the accompanying consolidated balance sheets of Equitable Resources, Inc. and Subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, common stockholders equity and cash flows for each of the three years in the period ended December 31, 2006. 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 auditing 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 Equitable Resources, Inc. and Subsidiaries at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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.

As discussed in Note 1 to the consolidated financial statements, in 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Equitable Resources, Inc. s internal control over financial reporting as of December 31, 2006, 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 19, 2007, expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 19, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUTING FIRM

The Board of Directors and Shareholders

Equitable Resources, Inc.

We have audited management s assessment, included in Management s Report on Internal Control over Financial Reporting and appearing in the accompanying Item 9A Controls and Procedures, that Equitable Resources, Inc. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Equitable Resources, Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management s assessment that Equitable Resources, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Equitable Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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 Equitable Resources, Inc. and Subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, common stockholders equity and cash flows for each of the three years in the period ended December 31, 2006 and our report dated February 19, 2007 expressed an unqualified opinion thereon.

Pittsburgh, Pennsylvania

February 19, 2007

51

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME
YEAR ENDED DECEMBER 31,

	2006	**2005**	**2004**
	(Thousands except per share amounts)		
Operating revenues	$ 1,267,910	$ 1,253,724	$ 1,045,183
Cost of sales	504,329	511,169	412,050
Net operating revenues (see Note 1)	763,581	742,555	633,133
Operating expenses:			
Operation and maintenance	104,620	95,369	87,988
Production	63,273	61,483	43,274
Selling, general and administrative	125,951	140,529	130,090
Office consolidation impairment charges	(2,908)	7,835	
Depreciation, depletion and amortization	100,122	93,527	82,076
Total operating expenses (see Note 1)	391,058	398,743	343,428
Operating income	372,523	343,812	289,705
Gain on sale of available-for-sale securities, net		110,280	3,024
Gain on exchange of Westport for Kerr-McGee shares			217,212
Charitable foundation contribution			(18,226)
Equity in earnings of nonconsolidated investments	260	762	856
Other income, net		1,195	3,692
Interest expense	47,052	44,437	42,520
Income from continuing operations before income taxes	325,731	411,612	453,743
Income taxes	109,706	153,038	154,953
Income from continuing operations	216,025	258,574	298,790
Income (loss) from discontinued operations, net of tax (benefit) provision of ($3,246), $10,485, and ($12,259) for the years ended December 31, 2006, 2005 and 2004, respectively	4,261	1,481	(18,936)
Net income	$ 220,286	$ 260,055	$ 279,854
Earnings per share of common stock:			
Basic:			
Income from continuing operations	$ 1.79	$ 2.14	$ 2.42
Income (loss) from discontinued operations	0.04	0.01	(0.15)
Net income	$ 1.83	$ 2.15	$ 2.27
Diluted:			
Income from continuing operations	$ 1.77	$ 2.09	$ 2.37
Income (loss) from discontinued operations	0.03	0.01	(0.15)
Net income	$ 1.80	$ 2.10	$ 2.22

See notes to consolidated financial statements.

EQUITABLE RESOURCES, INC. AND SUBSIDIRIES
STATEMENTS OF CONSOLIDATED CASH FLOWS
YEARS ENDED DECEMBER 31,

	2006 (Thousands)	2005	2004
Cash flows from operating activities:			
Net income	$ 220,286	$ 260,055	$ 279,854
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
(Income) loss from discontinued operations, net of tax	(4,261)	(1,481)	18,936
Provision for losses on accounts receivable	4,715	8,273	19,659
Depreciation, depletion and amortization	100,122	93,527	82,076
Office consolidation impairment charges	(2,908)	7,835	
Deferred income taxes	31,267	(92,912)	113,437
Excess tax benefits from share-based payment arrangements	(15,739)		
Gain on sale of available-for-sale securities, net		(110,280)	(3,024)
Gain on exchange of Westport for Kerr-McGee shares			(217,212)
Charitable foundation contribution			18,226
Recognition of prepaid forward production revenue			(10,363)
Amendment of prepaid forward contract, net			(31,260)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues	63,527	(78,049)	(69,024)
Margin deposits	317,821	(280,935)	(32,463)
Inventory	20,793	(85,296)	(45,420)
Prepaid expenses and other	(1,791)	(27,564)	(16,360)
Regulatory assets	1,146	(2,847)	506
Accounts payable	(29,292)	71,451	43,544
Derivative instruments, at fair value	(53,846)	(40,962)	994
Deferred income taxes	33,375	(32,288)	34,111
Pension contributions and settlements	(1,751)	(20,364)	
Other assets	6,960	(20,950)	(746)
Other current liabilities	(57,222)	83,059	28,198
Other credits	(13,914)	8,257	17,455
Net cash provided by (used in) continuing operating activities	619,288	(261,471)	231,124
Net cash used in discontinued operating activities		(50,491)	(51,126)
Net cash provided by (used in) operating activities.	619,288	(311,962)	179,998
Cash flows from investing activities:			
Capital expenditures	(404,536)	(275,798)	(201,813)
Purchase of interest in Eastern Seven Partners, L.P.		(57,500)	
Investment in available-for-sale securities	(2,471)	(4,009)	
Proceeds from sale of discontinued operations, net of purchase price adjustments	(724)	80,000	
Proceeds from sale of Kerr-McGee shares		460,467	42,880
Proceeds from sale of properties		141,991	
Net cash (used in) provided by continuing investing activities	(407,731)	345,151	(158,933)
Net cash provided by discontinued investing activities		2,595	439
Net cash (used in) provided by investing activities	(407,731)	347,746	(158,494)
Cash flows from financing activities:			
Dividends paid	(104,871)	(99,737)	(89,364)
Purchase of treasury stock		(122,250)	(118,472)
Proceeds from exercises under employee compensation plans	34,910	25,016	26,776
Excess tax benefits from share-based payment arrangements	15,739		
Repayments and retirements of long-term debt	(3,000)	(10,000)	(20,500)
Proceeds from issuance of long-term debt		150,000	
(Decrease) increase in short-term loans	(229,301)	69,801	95,899
Net cash (used in) provided by continuing financing activities	(286,523)	12,830	(105,661)
Net cash provided by discontinued financing activities		26,352	49,863
Net cash (used in) provided by financing activities	(286,523)	39,182	(55,798)
Net (decrease) increase in cash and cash equivalents	(74,966)	74,966	(34,294)

Cash and cash equivalents at beginning of year	74,966				34,294	
Cash and cash equivalents at end of year	$		$	74,966	$	
Cash paid during the year for:						
Interest (net of amount capitalized)	$	47,260	$	49,085	$	49,656
Income taxes	$	58,631	$	251,486	$	23,043

See notes to consolidated financial statements.

53

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS ENDED
DECEMBER 31,

	2006 (Thousands)	2005
Assets		
Current assets:		
Cash and cash equivalents	$	$ 74,966
Accounts receivable (less accumulated provision for doubtful accounts: 2006, $20,442; 2005, $23,329)	199,486	249,397
Unbilled revenues	40,627	58,958
Margin deposits with financial institutions	11	317,832
Inventory	269,128	289,921
Derivative instruments, at fair value	129,675	42,899
Prepaid expenses and other	62,523	60,732
Assets held for sale from discontinued operations		2,518
Total current assets	701,450	1,097,223
Equity in nonconsolidated investment	35,023	35,555
Property, plant and equipment:		
Equitable Utilities	1,215,177	1,155,946
Equitable Supply	2,402,120	2,080,151
Total property, plant and equipment	3,617,297	3,236,097
Less: accumulated depreciation and depletion	1,239,826	1,152,892
Net property, plant and equipment	2,377,471	2,083,205
Investments, available-for-sale	31,270	25,194
Other assets:		
Regulatory assets	78,719	70,055
Other	32,978	31,053
Total other assets	111,697	101,108
Total assets	$ 3,256,911	$ 3,342,285

See notes to consolidated financial statements.

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS ENDED
DECEMBER 31,

	2006 (Thousands)	2005
Liabilities and Common Stockholders Equity		
Current liabilities:		
Current portion of long-term debt	$ 10,000	$ 3,000
Short-term loans	135,999	365,300
Accounts payable	213,326	242,618
Derivative instruments, at fair value	570,251	1,264,204
Other current liabilities	150,203	217,374
Total current liabilities	1,079,779	2,092,496
Debentures and medium-term notes	753,500	763,500
Deferred and other credits:		
Deferred income taxes and investment tax credits	338,012	24,042
Pension and other post-retirement benefits	50,947	20,870
Other credits	88,393	86,909
Common stockholders equity:		
Common stock, no par value, authorized 320,000 shares; shares issued: 2006 and 2005, 149,008	366,856	358,684
Treasury stock, shares at cost: 2006, 27,405; 2005, 29,102; (net of shares and cost held in trust for deferred compensation of 159, $2,724 and 142, $2,429)	(469,584)	(496,511)
Retained earnings	1,363,310	1,247,895
Accumulated other comprehensive loss	(314,302)	(755,600)
Total common stockholders equity	946,280	354,468
Total liabilities and common stockholders equity	$ 3,256,911	$ 3,342,285

See notes to consolidated financial statements.

55

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES
STATEMENTS OF COMMON STOCKHOLDERS EQUITY
YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

	Common Stock Shares Outstanding (Thousands)	No Par Value	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Common Stockholders Equity
Balance, December 31, 2003	124,732	$ 52,988	$ 897,087	$ 15,265	$ 965,340
Comprehensive income (net of tax):					
Net income			279,854		279,854
Net change in cash flow hedges:					
Natural gas, net of tax benefit of $82,277 (see Note 3)				(138,926)	(138,926)
Interest rate				397	397
Gain on exchange of Westport stock				(143,360)	(143,360)
Unrealized gain on available-for-sale securities: Westport (to date of merger)				43,731	43,731
Kerr-McGee (from date of merger)				36,334	36,334
Other				371	371
Minimum pension liability adjustment, net of tax benefit of $3,009				5,841	5,841
Total comprehensive income					84,242
Dividends ($0.720 per share)			(89,364)		(89,364)
Stock-based compensation plans, net	2,030	32,926			32,926
Stock repurchases	(4,700)	(118,472)			(118,472)
Balance, December 31, 2004	122,062	(32,558)	1,087,577	(180,347)	874,672
Comprehensive income (net of tax):					
Net income			260,055		260,055
Net change in cash flow hedges:					
Natural gas, net of tax benefit of $324,817 (see Note 3)				(543,716)	(543,716)
Interest rate				97	97
Unrealized gain on available-for-sale securities: Kerr-McGee				(36,334)	(36,334)
Other				375	375
Minimum pension liability adjustment, net of tax benefit of $211				4,325	4,325
Total comprehensive loss					(315,198)
Dividends ($0.820 per share)			(99,737)		(99,737)
Stock-based compensation plans, net	1,412	16,981			16,981
Stock repurchases	(3,568)	(122,250)			(122,250)
Balance, December 31, 2005	119,906	(137,827)	1,247,895	(755,600)	354,468
Comprehensive income (net of tax):					
Net income			220,286		220,286
Net change in cash flow hedges:					
Natural gas, net of tax of $272,066 (see Note 3)				454,817	454,817
Interest rate				116	116
Unrealized gain on available-for-sale securities				2,399	2,399
Pension and other post-retirement benefits liability adjustment prior to the adoption of SFAS No. 158, net of tax benefit of $730				(1,024)	(1,024)
Total comprehensive income					676,594
				(15,010)	(15,010)

Pension and other post-retirement benefits liability adjustment due to the adoption of SFAS No. 158, net of tax benefit of $9,988					
Dividends ($0.87 per share)			(104,871)		(104,871)
Stock-based compensation plans, net	1,697	35,099			35,099
Balance, December 31, 2006	121,603	$ (102,728)	$ 1,363,310	$ (314,302)	$ 946,280

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.

EQUITABLE RESOURCES, INC. AND SUBSIDIRIES
NOTE TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2006

1. Summary of Significant Accounting Policies

Principles of Consolidation: The Consolidated Financial Statements include the accounts of Equitable Resources, Inc. and all subsidiaries, ventures and partnerships in which a controlling equity interest is held (Equitable or the Company). All significant intercompany accounts and transactions have been eliminated in consolidation. Equitable utilizes the equity method of accounting for companies where its ownership is less than or equal to 50% and significant influence exists.

Reclassification: The Consolidated Financial Statements and related footnote disclosures have been reclassified to reflect the operating results of the NORESCO segment as discontinued operations for all periods presented. See Note 7 for further information. Additionally, certain previously reported amounts have been reclassified to conform to the current year presentation.

Stock Split: On September 1, 2005, the Company effected a two-for-one stock split payable to shareholders of record on August 12, 2005. All share and per share information has been retroactively adjusted to reflect the stock split.

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: The Company s inventory balance consists of natural gas stored underground and materials and supplies recorded at the lower of average cost or market.

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

	December 31, 2006	**2005**
	(Thousands)	
Utility plant	$ 1,207,311	$ 1,148,063
Accumulated depreciation and amortization	413,215	392,877
Net utility plant	794,096	755,186
Oil and gas producing properties, successful efforts method	1,752,222	1,551,677
Accumulated depletion	566,118	518,426
Net oil and gas producing properties	1,186,104	1,033,251
Other properties, at cost less accumulated depreciation	397,271	294,768
Net property, plant and equipment	$ 2,377,471	$ 2,083,205

Utility property, plant and equipment, principally 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, 2006, and December 31, 2005, was approximately 4% of net Utility properties.

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 on the unit-of-production method. The 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. Equitable Supply calculates a single depletion field including all reserves located in Kentucky, West Virginia, Virginia and Pennsylvania. Costs of exploratory dry holes, geological and geophysical, delay rentals and other property carrying costs are charged to expense. The majority of the Company s oil and gas producing properties consists of gas producing properties which were depleted at a rate of $0.62/Mcf and $0.59/Mcf produced for the years ended December 31, 2006, and December 31, 2005, respectively.

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 them to their respective carrying values. 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 and forward market prices for oil and gas. Proved oil and gas properties that have carrying amounts in excess of estimated future cash flows are deemed unrecoverable. Those properties are then written down to fair value, which is estimated using assumptions that marketplace participants would use in their estimates of fair value. In developing estimates of fair value, the Company used forward market prices. For the years ended December 31, 2006, 2005 and 2004, the Company did not recognize impairment charges on oil and gas properties.

Additionally, the costs of unproved oil and gas properties are periodically assessed. If unproved properties are determined to be productive, the related costs are transferred to proved oil and gas properties. If unproved properties are determined not to be productive, or if the value has been otherwise impaired, the excess carrying value is charged to expense. For additional information on oil and gas properties, see Note 24 (unaudited).

The Company also had $397.3 million and $294.8 million of other net property at December 31, 2006, and December 31, 2005, respectively. These items are carried at cost and depreciation is calculated using the straight-line method based on estimated service lives. This property consists largely of gathering systems (25 year estimated service life), buildings (35 year estimated service life), office equipment (3-7 year estimated service life), vehicles (5 year estimated service life), and computer and telecommunications equipment and systems (3-7 year estimated service life).

Major maintenance projects that do not increase the overall life of the related assets are expensed. When the 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 oil and gas reserves from the depletion pool 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: The Company s distribution operations are subject to comprehensive regulation by the PA PUC and the WV PSC. The Company 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 Company s interstate pipeline operations are subject to regulation by the FERC. Accounting for the Company s regulated operations is performed in accordance with the provisions of SFAS No. 71. The application of this accounting policy 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, the Company defers the difference between its purchased natural gas cost, less refunds, and the billing of

58

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.

When any portion of the Company s distribution or pipeline operations ceases to meet the criteria for application of regulatory accounting treatment for all or part of their operations, the regulatory assets and liabilities related to those portions are eliminated from the Consolidated Balance Sheets and are included in the Statements of Consolidated Income in the period in which the discontinuance of regulatory accounting treatment occurs.

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

	Years Ended December 31,		
	2006	**2005**	**2004**
	(Thousands)		
Distribution revenues	$ 445,168	$ 469,102	$ 422,438
Pipeline revenues	74,010	57,534	55,123
Total regulated revenue	519,178	526,636	477,561
Distribution purchased gas costs	301,833	312,244	263,313
Pipeline purchased gas costs	1,424	3,767	
Total purchased gas costs	303,257	316,011	263,313
Distribution net revenue	143,335	156,858	159,125
Pipeline net revenue	72,586	53,767	55,123
Total regulated net revenue	215,921	210,625	214,248
Distribution operating expenses	108,528	116,536	102,248
Pipeline operating expenses	39,346	36,422	30,467
Total regulated operating expenses	$ 147,874	$ 152,958	$ 132,715

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 chief executive officer, the executive vice-president of finance and administration, 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 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.

All derivative instruments are accounted for in accordance with SFAS No. 133. As a result, the Company recognizes all derivative instruments as either assets or liabilities and measures the effectiveness of the hedges, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at fair value. If the gain (loss) for the hedging instrument is greater than the loss (gain) on the hedged item, hedge ineffectiveness is recorded. The measurement of fair value is based upon actively quoted market prices when available. In the absence of actively quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based upon valuation methodologies deemed appropriate by the Company s CRC. The Company assesses the effectiveness of hedging relationships both at the inception of the hedge and on an on-going 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 (loss), net of tax, and is subsequently reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The ineffective portion of the cash flow hedge is immediately recognized in operating revenues in the Statements of Consolidated Income. If a cash flow hedge is terminated before the settlement date of the hedged item, the amount of accumulated other comprehensive income (loss) recorded up to that date would remain accrued provided that the forecasted transaction remains probable of occurring, and going forward, the change in fair value of the derivative instrument would be recorded in earnings. The derivative instruments that comprise the amount recorded in accumulated other comprehensive income (loss) have been designated and qualify as cash flow hedges. The Company reports all gains and losses on its energy trading contracts net on its Statements of Consolidated Income in accordance with EITF No. 02-3.

Capitalized Interest: Interest costs for the construction of certain long-term assets are capitalized and amortized over the related assets estimated useful lives. Interest costs during 2006, 2005 and 2004 of $0.3 million, $0.2 million and $0.1 million, respectively, were capitalized as a portion of the cost of the related long-term assets.

Impairment of Long-Lived Assets: In accordance with SFAS No. 144, whenever events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable, the Company reviews its long-lived assets for impairment by first comparing the carrying value of the assets to the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the assets. If the carrying value exceeds the sum of the assets undiscounted cash flows, the Company estimates an impairment loss by taking the difference between the carrying value and fair value of the assets.

Revenue Recognition: Sales of natural gas to utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain customers do not necessarily coincide with accounting periods used for financial reporting purposes. The Company follows the revenue accrual method of accounting for utility 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. Revenue is recognized for production activities when deliveries of natural gas, crude oil and natural gas liquids are made. Revenues from natural gas transportation and storage activities are recognized in the period service is provided. Revenues from energy marketing activities are recognized when deliveries occur. In accordance with EITF No. 02-3, only revenues associated with energy trading activities that do not result in physical delivery of an energy commodity (i.e. are settled in cash) are recorded using mark-to-market accounting. The revenues associated with the physical delivery of an energy commodity are recognized at contract value when delivered. Revenues associated with the Company s natural gas advance sales contracts are recognized as natural gas is gathered and delivered.

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.

Other investments in equity securities which are generally under 20% ownership and where the Company does not exert significant influence over operating and financial polices are accounted for as available-for-sale in accordance with SFAS No. 115 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 (loss). The Company utilizes the specific identification method to determine the cost of the securities sold.

APB No. 18 requires a company to recognize 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. In accordance with SFAS No. 115, the Company continually reviews its available-for-sale investments 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. No other than temporary decline in fair value was recorded in 2006, 2005 or 2004.

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. Any refinements to prior years taxes made due to subsequent information are reflected as adjustments in the current period. Separate income taxes are calculated for income from continuing operations, discontinued operations, and items charged or credited directly to stockholders equity.

Deferred income tax assets and liabilities are determined based on temporary differences between the financial reporting and tax bases of assets and liabilities in accordance with SFAS No. 109 which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of such temporary differences. SFAS No. 109 also requires that deferred tax assets be 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.

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 is computed by dividing net income by the weighted average number of common shares outstanding during the period, without considering any dilutive items. Diluted EPS is computed by dividing net income adjusted for the assumed conversion of debt 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 for a detailed calculation.

Asset Retirement Obligations: SFAS No. 143 requires that the fair value of the Company s plugging and abandonment obligations 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 following table presents a reconciliation of the beginning and ending carrying amounts of the Company s asset retirement obligations. The Company does not have any assets that are legally restricted for purposes of settling these obligations.

	Year ended December 31, 2006 (Thousands)
Asset retirement obligation as of beginning of period	$ 46,126
Accretion expense	3,134
Liabilities incurred	619
Liabilities settled	(1,359)
Asset retirement obligation as of end of period	$ 48,520

Self-Insurance: The Company is self-insured for certain losses related to workers compensation. 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:

Share-Based Compensation

The Company adopted SFAS No. 123R as of January 1, 2006. The Company previously accounted for share-based compensation transactions using the intrinsic value method of APB No. 25. Under SFAS No. 123R, an entity must recognize the compensation cost related to employee services received in exchange for all forms of share-based payments to employees, including employee stock options, as an expense in its income statement. The compensation cost of the award is generally measured based on the grant-date fair value of the award. See Note 16 for further discussion of the Company s accounting for share-based payments.

Employers Accounting for Defined Benefit Pension and Other Postretirement Plans

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize a benefit plan s funded status in its statement of financial position, measure a benefit plan s assets and obligations as of the end of the employer s fiscal year and recognize the changes in the benefit plan s funded status in other comprehensive income in the year in which the changes occur. SFAS No. 158 s requirement to recognize the funded status of a benefit plan and the new disclosure requirements were effective as of December 31, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. See Footnote 13 for information regarding the adoption of SFAS No. 158 as of December 31, 2006.

The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, which provides entities with an option to report selected financial assets and liabilities at fair value. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This Statement is effective as of the beginning of the first fiscal year that begins after

November 15, 2007. The Company is currently evaluating the impact that SFAS No. 159 will have on its consolidated financial statements.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, which establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is currently evaluating the impact that SFAS No. 157 will have on its consolidated financial statements.

Accounting for Uncertain Tax Positions

In June 2006, the FASB issued FIN 48, which applies to all open tax positions accounted for in accordance with SFAS No. 109. This Interpretation is intended to result in increased relevance and comparability in financial reporting of income taxes and to provide more information about the uncertainty in income tax assets and liabilities. This Interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently evaluating the impact of this Interpretation and does not expect it to be material.

2. Financial Information by Business Segment

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 executive officer (chief operating decision maker) in deciding how to allocate resources. The Company reports its operations in two segments, which reflect its lines of business. The Equitable Utilities segment s operations comprise the sale and transportation of natural gas to customers at state-regulated rates, interstate pipeline gathering, transportation and storage of natural gas subject to federal regulation, the unregulated marketing of natural gas and limited trading activities. The Equitable Supply segment s activities comprise the development, production, gathering, marketing and sale of natural gas and a small amount of associated oil and the extraction and sale of natural gas liquids.

Operating segments are evaluated on their contribution to the Company s consolidated results based on operating income, equity in earnings of nonconsolidated investments, and other income, net. Interest expense and income taxes are managed on a consolidated basis. Headquarters costs are billed to the operating segments based upon a fixed allocation of the headquarters annual operating budget. Differences between budget and actual headquarters expenses are not allocated to the operating segments.

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

	Years Ended December 31, 2006 (Thousands)	2005	2004
Revenues from external customers:			
Equitable Utilities	$ 843,164	$ 846,457	$ 731,861
Equitable Supply	488,571	489,191	390,428
Less: intersegment revenues (a)	(63,825)	(81,924)	(77,106)
Total	$ 1,267,910	$ 1,253,724	$ 1,045,183
Total operating expenses:			
Equitable Utilities	$ 149,801	$ 155,110	$ 134,556
Equitable Supply	219,407	195,610	163,059
Unallocated expenses (b)	21,850	48,023	45,813
Total	$ 391,058	$ 398,743	$ 343,428
Operating income:			
Equitable Utilities	$ 125,209	$ 98,254	$ 108,149
Equitable Supply	269,164	293,581	227,369
Unallocated expenses (b)	(21,850)	(48,023)	(45,813)
Total operating income	$ 372,523	$ 343,812	$ 289,705

	Years Ended December 31, 2006 (Thousands)	2005	2004
Reconciliation of operating income to net income:			
Equity in earnings of nonconsolidated investments:			
Equitable Supply	$ 129	$ 493	$ 688
Unallocated	131	269	168
Total	$ 260	$ 762	$ 856
Other income, net:			
Equitable Supply	$	$	$ 576
Unallocated (c)		1,195	3,116
Total	$	$ 1,195	$ 3,692
Gain on sale of available-for-sale securities, net		110,280	3,024
Gain on exchange of Westport for Kerr-McGee shares			217,212
Charitable foundation contribution			(18,226)
Interest expense	47,052	44,437	42,520
Income taxes	109,706	153,038	154,953
Income from continuing operations	216,025	258,574	298,790
Income (loss) from discontinued operations	4,261	1,481	(18,936)
Net income	$ 220,286	$ 260,055	$ 279,854

64

	As of December 31, 2006 (Thousands)	2005
Segment assets:		
Equitable Utilities	$ 1,407,024	$ 1,412,215
Equitable Supply	1,794,485	1,844,883
Total operating segments	3,201,509	3,257,098
Headquarters assets, including cash and short-term investments	55,402	82,669
Total operating assets	3,256,911	3,339,767
Assets held for sale from discontinued operations		2,518
Total assets	$ 3,256,911	$ 3,342,285

	Years Ended December 31, 2006 (Thousands)	2005	2004
Significant noncash expense (income) items:			
Equitable Utilities:			
Increase in deferred purchased natural gas cost	$ 3,591	$ 35,806	$ 13,270
Increase (decrease) in regulatory asset valuation allowance	24	(204)	6,004
Impairment charges (d)	(2,396)	3,841	
Equitable Supply:			
Impairment charges (d)		519	
Unallocated:			
Impairment charges (d)	(512)	3,475	
Total	$ 707	$ 43,437	$ 19,274

	Years Ended December 31, 2006 (Thousands)	2005	2004
Depreciation, depletion and amortization:			
Equitable Utilities	$ 28,731	$ 27,874	$ 25,629
Equitable Supply	70,500	64,897	55,836
Other	891	756	611
Total	$ 100,122	$ 93,527	$ 82,076
Expenditures for segment assets:			
Equitable Utilities	$ 64,974	$ 61,349	$ 56,274
Equitable Supply (e)	336,748	264,095	141,661
Other	2,814	7,854	3,878
Total	$ 404,536	$ 333,298	$ 201,813

(a) Intersegment revenues primarily represent sales from Equitable Supply to the unregulated marketing affiliate of Equitable Utilities.

(b) Unallocated expenses consist primarily of certain performance-related incentive costs and administrative costs that are not allocated to the operating segments. For the year ended December 31, 2004, unallocated expenses also include $13.4 million related to the settlement of the cash balance portion of a defined benefit pension plan as more fully discussed in Note 13.

(c) Unallocated other income, net for the years ended December 31, 2005 and 2004 relates to pre-tax dividend income of $1.2 million and $3.1 million, respectively, for the Kerr-McGee Corporation shares held by the Company during those periods.

65

(d) The impairment charges for the years ended December 31, 2006 and 2005 relate to the consolidation of the Company s administrative operations in a building at the North Shore in Pittsburgh, Pennsylvania. See Note 21.

(e) Expenditures for segment assets for 2005 include $57.5 million for the acquisition of the 99% limited partnership interest in Eastern Seven Partners, L.P. See Note 5.

3. Derivative Instruments

Derivative Commodity Instruments

The various derivative commodity instruments used by the Company to hedge its exposure to variability in expected future cash flows associated with the fluctuations in the price of natural gas related to the Company s forecasted sale of equity production and forecasted natural gas purchases and sales have been designated and qualify as cash flow hedges. 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. Exchange-traded instruments are generally settled with offsetting positions but may be settled by delivery or receipt of commodities. OTC arrangements require settlement in cash.

The fair value of these derivative commodity instruments is presented below:

	As of December 31, 2006	2005
	(Thousands)	
Asset	$ 129,675	$ 36,005
Liability	(544,444)	(1,209,580)
Net liability	$ (414,769)	$ (1,173,575)

These amounts are included in the Consolidated Balance Sheets as derivative instruments, at fair value. The net amount of derivative instruments, at fair value, changed between years primarily as a result of the 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 392.6 Bcf and 383.5 Bcf as of December 31, 2006 and 2005, respectively, and are primarily related to natural gas swaps. The open positions at December 31, 2006 had maturities extending through December 2013.

The Company had deferred net losses of $286.2 million and $741.0 million in accumulated other comprehensive loss, net of tax, as of December 31, 2006 and 2005, 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 $89.1 million of net unrealized losses on its derivative commodity instruments reflected in accumulated other comprehensive loss, net of tax, as of December 31, 2006 will be recognized in earnings during the next twelve months due to the physical settlement of hedged transactions. This recognition occurs through a reduction in the Company s net operating revenues resulting in the average hedged price becoming the realized sales price.

The net change in accumulated other comprehensive loss related to derivatives is presented below:

	Years Ended December 31, 2006 (Thousands)	2005	2004
Net unrealized gain (loss)	$ 370,395	$ (690,893)	$ (182,504)
Net realized loss	84,422	147,177	43,578
Net gain (loss)	$ 454,817	$ (543,716)	$ (138,926)

For the years ended December 31, 2006, 2005 and 2004, ineffectiveness associated with the Company s derivative instruments designated as cash flow hedges increased (decreased) earnings by approximately $0.4 million, $(0.1) million and $(2.0) million, respectively. These amounts are included in operating revenues in the Statements of Consolidated Income.

The Company conducts trading activities through its unregulated marketing group. The function of the Company s trading business is to contribute to the Company s earnings by taking market positions within defined limits subject to the Company s corporate risk management policy. At December 31, 2006, the absolute notional quantities of the futures and swaps held for trading purposes totaled 3.4 Bcf and 22.4 Bcf, respectively.

Below is a summary of the activity of the fair value of the Company s derivative commodity contracts with third parties held for trading purposes during the year ended December 31, 2006 (in thousands).

Fair value of contracts outstanding as of December 31, 2005	$ (330)
Contracts realized or otherwise settled	137
Other changes in fair value	774
Fair value of contracts outstanding as of December 31, 2006	$ 581

There were no significant adjustments to the fair value of the Company s derivative contracts held for trading purposes relating to changes in valuation techniques and assumptions during the years ended December 31, 2006 and 2005.

The following table presents the maturities and the fair valuation source for the Company s derivative instruments that were held for trading purposes as of December 31, 2006.

Net Fair Value of Third Party Contract Assets at Period-End

Source of Fair Value	Maturity Less than 1 Year (Thousands)	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
Prices actively quoted (NYMEX) (1)	$ 396	$	$	$	$ 396
Prices provided by other external sources (2)	173	12			185
Net derivative assets	$ 569	$ 12	$	$	$ 581

(1) Contracts include futures and fixed price swaps

(2) Contracts include basis swaps

The overall portfolio of the Company s energy derivatives 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 energy derivative portfolio is managed to

67

complement the physical transaction portfolio, reducing overall risks within limits. Therefore, an adverse impact to the fair value of the portfolio of energy derivatives 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 physical transactions, assuming the energy derivatives are not closed out in advance of their expected term, the energy derivatives continue to function effectively as hedges of the underlying risk and the anticipated transactions occur as expected.

As part of the purchase of the limited partnership interest in Eastern Seven Partners, L.P. (ESP) as discussed in Note 5, the Company assumed derivative liabilities of $47.3 million for the fair value of ESP s hedges. These hedges were effectively closed out at acquisition by the purchase of offsetting positions. The Company does not treat these derivatives as hedging instruments under SFAS No. 133. The fair value of these derivative instruments at December 31, 2006 was a $10.0 million liability. These amounts are included in the Consolidated Balance Sheet as derivative instruments, at fair value.

In May 2005, the Company sold certain non-core gas properties, as discussed in Note 4. As part of this transaction, the Company closed out certain cash flow hedges associated with forecasted production at these locations by purchasing offsetting positions. The Company does not treat these derivatives as hedging instruments under SFAS No. 133. The fair value of these derivative instruments at December 31, 2006 was a $14.3 million liability. These amounts are included in the Consolidated Balance Sheet as derivative instruments, at fair value.

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 had less than $0.1 million of such deposits in its Consolidated Balance Sheet as of December 31, 2006. As of December 31, 2005, the Company recorded such deposits in the amount of $267.9 million in its Consolidated Balance Sheet.

When the Company enters into exchange-traded natural gas contracts, exchanges require participants, including 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. 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 prices, volatility and the time to expiration of the related contract and are subject to change at the exchanges discretion. The Company recorded a liability of $7.9 million in its Consolidated Balance Sheet as of December 31, 2006, representing amounts received from brokers as a result of the related contracts having a positive fair value. The Company recorded an asset for deposits in the amount of $49.9 million in its Consolidated Balance Sheet as of December 31, 2005.

Other Derivative Instruments

In July 2004, the Company entered into three 7.5 year secured variable share forward transactions. Each transaction had a different counterparty, covered 2.0 million shares of Kerr-McGee Corporation (Kerr-McGee) common stock, contained a collar and permitted receipt of an amount up to the net present value of the floor price prior to maturity. Upon maturity of each transaction, the Company was obligated to deliver to the applicable counterparty, at the Company s option, no more than 2.0 million Kerr-McGee shares or cash in an equivalent value. The collars effectively limited the Company s cash flow exposure upon the forecasted disposal of 6.0 million Kerr-McGee shares. A variable portion of the dividends received on the underlying Kerr-McGee shares was paid to each counterparty depending upon the hedged position of such counterparty.

In May 2005, the Company terminated the three variable share forward transactions. In connection with the termination, the Company incurred a termination cost of $95.8 million and sold 4.3 million Kerr-McGee shares to its three counterparties to cover its counterparties respective hedged positions. See Note 9 for further discussion of transactions related to the Kerr-McGee shares.

4. Sale of Properties

In May 2005, the Company sold certain non-core gas properties and associated gathering assets for approximately $142 million after purchase price adjustments. In accordance with SFAS No. 19, this sale of only a portion of the Company s gas properties was treated as a normal retirement with no gain or loss recognized, as doing so did not significantly affect the depletion rate. See Note 24 for further discussion of changes to the Company s reserves during 2005.

5. Acquisitions

On March 1, 2006, the Company entered into a definitive agreement to acquire Dominion Resources, Inc. s natural gas distribution assets in Pennsylvania and in West Virginia for approximately $970 million, subject to adjustments, in a cash transaction for the stock of The Peoples Natural Gas Company and Hope Gas, Inc. The transaction requires approvals from the PA PUC and the WV PSC and is also under review by the Pennsylvania Attorney General and by the Federal Trade Commission (FTC). On February 9, 2007 an administrative law judge for the PA PUC issued an initial decision approving the stock acquisition, subject to the terms and conditions of the Joint Petition for Settlement filed by the Company and a number of the intervening parties. The Joint Petition for Settlement includes, among other things, an agreement by the Company that Equitable Gas Company and The Peoples Natural Gas Company will not make base rate case filings prior to January 1, 2009. Under the Commission s rules a period for filing exceptions and reply exceptions has begun to run. Based upon the thorough manner in which the administrative law judge addressed the testimony of opposing parties, the Company believes it likely that the PA PUC will approve the stock acquisition when it reviews the application in March or April of 2007. The WV PSC procedural schedule calls for hearings in mid-May 2007. The WV PSC staff and consumer advocate, the Independent Oil and Gas Association of West Virginia and the Utility Workers Union of America Local 69 Division 1 have intervened in the West Virginia regulatory case. The Company continues to engage in settlement negotiations with these interveners. The Company is complying with the information requests of the Pennsylvania Attorney General and the FTC and is targeting an approval timeframe not long after receiving approval from the PA PUC. No assurance is given that the targeted timeframes will be achieved. The Company s acquisition agreement expires on March 31, 2007 unless a closing has not occurred due to a failure to obtain a required governmental consent or authorization and such is being diligently pursued, in which case the expiration date is automatically extended to June 30, 2007. The agreement will then terminate if no closing occurs by June 30, 2007, unless the parties agree to an extension. The assets to be acquired will increase: customers in the distribution operations by 475,000 or 173%; total storage capacity by 33 Bcf or 60%, miles of gathering pipelines by 936 miles; gathered volumes by 40%; and miles of high pressure transmission by 466 miles or 42%. Transition planning activities have commenced at Equitable Utilities to plan for the integration of the assets, resources, and business processes of The Peoples Natural Gas Company and Hope Gas, Inc. s into Equitable Resources.

In January 2005, the Company purchased the limited partnership interest in ESP for cash of $57.5 million and assumed liabilities of $47.3 million. See Note 24 for further discussion of changes to the Company s reserves during 2005.

6. Income Taxes

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

	December 31, 2006 (Thousands)	2005
Deferred tax liabilities (assets):		
Drilling and development costs expensed for income tax reporting	$ 410,721	$ 380,283
Other comprehensive loss	(192,612)	(455,215)
Tax depreciation in excess of book depreciation	105,318	88,485
Regulatory temporary differences	29,326	27,281
Deferred purchased gas cost	21,358	10,196
Deferred compensation plans	(2,130)	(2,235)
Investment tax credit	(3,654)	(3,921)
Uncollectible accounts	(9,210)	(8,211)
Postretirement benefits	(9,245)	(4,348)
Other, net of valuation allowance of $3,773 and $6,830, respectively	(5,753)	(16,501)
Total (including amounts classified as current liabilities of $15,011 and $1,736 for 2006 and 2005, respectively)	$ 344,119	$ 15,814

The net deferred tax asset relating to the Company s accumulated other comprehensive loss balance as of December 31, 2006 was comprised of a $173.7 million deferred tax asset related to the Company s net unrealized loss from hedging transactions, a $9.5 million deferred tax asset related to other post-retirement benefits, a $11.5 million deferred tax asset related to the pension plans, and a $2.1 million deferred tax liability related to the Company s net unrealized gain on available-for-sale securities. The net deferred tax asset relating to the Company s other comprehensive loss balance as of December 31, 2005 was comprised of a $445.7 million deferred tax asset related to the Company s net unrealized loss from hedging transactions, a $10.4 million deferred tax asset related to the minimum pension liability adjustment and an $0.9 million deferred tax liability related to the Company s net unrealized gain on available-for-sale securities.

Income tax expense is summarized as follows:

	Years Ended December 31, 2006 (Thousands)	2005	2004
Current:			
Federal	$ 75,875	$ 237,422	$ 39,391
State	2,564	8,528	2,125
Subtotal	78,439	245,950	41,516
Deferred:			
Federal	41,064	(92,194)	113,031
State	(9,797)	(718)	406
Subtotal	31,267	(92,912)	113,437
Total	$ 109,706	$ 153,038	$ 154,953

70

Provisions for income taxes differ from amounts computed at the Federal statutory rate of 35% on pretax income from continuing operations. The reasons for the difference are summarized as follows:

	Years Ended December 31, 2006 (Thousands)	2005	2004
Tax at statutory rate	$ 114,006	$ 144,064	$ 158,810
State income taxes	(8,130)	5,076	1,645
Federal tax credits and incentives	(1,609)	(3,604)	(707)
Book/Tax basis differences	(1,050)	(4,410)	(3,215)
Incentive or deferred compensation	93	15,300	1,400
Other	6,396	(3,388)	(2,980)
Income tax expense	$ 109,706	$ 153,038	$ 154,953
Effective tax rate	33.7 %	37.2 %	34.2 %

During 2006, state income taxes decreased as a result of a change to state income tax rates as computed in accordance with SFAS No. 109 and the release of a state valuation allowance related to a state net operating loss carryover. During 2006, the Company reduced its valuation allowance for state net operating loss carryovers by $3.1 million as a result of an anticipated increase in prospective realization of those deferred tax assets. The other category does not include any items that are individually significant.

During 2005, following a moratorium imposed on the Company by the IRS for claiming any research and development (R&D) tax credits, the Company completed an analysis of its R&D expenditures for the years 2001 through 2005. This analysis resulted in a research tax credit that generated a tax benefit of $3.8 million for those periods, net of a tax reserve of $1.2 million. The study was extended to 2006 with a recorded tax benefit of $0.6 million, net of a tax reserve of $0.3 million.

During 2005, the Qualified Production Activities Deduction under Section 199 of the IRC, which provides for a phased-in deduction related to qualifying production activities, was provided for the first time under the American Jobs Creation Act of 2004. The Company recorded an income tax benefit for certain qualifying production activities of approximately $0.6 million and $1.9 million for 2006 and 2005, respectively.

During 2005, the Company recorded $15.3 million in tax benefit disallowances under Section 162(m) of the IRC, primarily as the result of impairment of previously recorded deferred tax assets related to the employee deferred compensation programs and the 2003 Executive Performance Incentive Program.

During 2003, the Company requested permission to change its method of accounting for inventory and self-constructed property in accordance with IRC Section 263A to use the simplified service cost method and simplified production method of capitalizing costs. During 2005, the IRS and the U.S. Treasury Department issued guidance providing for further clarification indicating that certain self-constructed property does not qualify as eligible property for the simplified methods. In 2006, the Company requested and was granted permission to conform its capitalization method to the facts and circumstances method and believes that it is appropriately reserved for any tax exposures for prior years.

The consolidated Federal income tax liability of the Company has been settled with the IRS through 1997. The IRS has completed its review of the Company s Federal income tax filings for the 1998 through 2000 years and the Company believes that only minor issues remain to be resolved. The IRS is expected to survey the 2001 and 2002 Federal income tax filings and audit years 2003 and forward. The Company also is the subject of various routine state income tax examinations. The Company believes that it is appropriately reserved for any tax exposures.

An income tax benefit of $18.6 million, $18.0 million and $7.8 million for the years ended December 31, 2006, 2005 and 2004, respectively, triggered by the exercise of nonqualified employee stock options and vesting of restricted share awards is reflected as an addition to common stockholders equity.

The Company has recorded a deferred tax asset of $7.3 million, net of valuation allowances of $2.9 million, related to tax benefits from state net operating loss carryforwards with various expiration dates ranging from 2013 to 2026.

7. Discontinued Operations

In the fourth quarter of 2005, the Company sold its NORESCO domestic business for $82 million before customary purchase price adjustments. Income from discontinued operations for the year ended December 31, 2005 included after-tax charges totaling $18.7 million, including $13.7 million which related to the recording of income taxes associated with the difference between the book and tax basis of the NORESCO assets sold, and $5.0 million of after-tax losses on the sale related to other costs incurred as a result of this sale.

In the fourth quarter of 2006, the Company recorded a tax benefit of $3.2 million related to a reduced tax liability on the sale. The Company also reassessed its remaining reserves for costs incurred related to the sale and recorded after-tax income of $1.1 million as a result. These items are included in income from discontinued operations in the Company s Statement of Consolidated Income for the year ended December 31, 2006.

In 2006, the Company completed the sale of the remaining interest in its investment in IGC/ERI Pan-Am Thermal Generating Limited (Pan Am), previously included in the NORESCO business segment, for total proceeds of $2.6 million. The Company did not record a gain or loss on this sale.

Cash flows generated from the discontinued operations and the proceeds received from the sale of the Pan Am investment of $2.6 million and of the NORESCO Domestic operations of $80.0 million are included in the Consolidated Statements of Cash Flows for the years ended December 31, 2006 and 2005, respectively.

Total operating revenues reclassified to discontinued operations for the years ended December 31, 2005 and 2004 were $143.5 million and $146.4 million, respectively. Interest expense of discontinued operations allocated based upon a ratio of the net assets of the discontinued operations to the overall net assets of the Company was $1.5 million for each of the years ended December 31, 2005 and 2004.

8. Equity in Nonconsolidated Investment

The Company has an ownership interest in a nonconsolidated investment that is accounted for under the equity method of accounting. The following table summarizes the equity in the nonconsolidated investment.

Investees	Location	Interest Type	Ownership as of December 31, 2006	December 31, 2006 (Thousands)	2005
Appalachian Natural Gas Trust (ANGT)	USA	Limited	1 %	$ 35,023	$ 35,555

The Company s ownership share of the earnings for 2006, 2005 and 2004 related to the total investments was $0.3 million, $0.8 million and $0.9 million, respectively.

Equitable Supply s equity investment in ANGT represents an ownership interest in transactions by which natural gas producing properties located in the Appalachian Basin region of the United States were sold. As of December 31, 2006, Equitable Supply s investment in ANGT totaled $23.3 million, while the Company s total investment was $35.0 million. As of December 31, 2005, Equitable Supply s investment in ANGT totaled $23.7 million, while the Company s total investment was $35.6 million. The Company did not make any additional equity investments in nonconsolidated investments during 2006 or 2005.

As discussed in Note 5, the Company purchased the 99% limited partnership interest in ESP in January 2005. The financial position and results of operations of ESP have been consolidated in the Company s Consolidated Financial Statements as of and for the years ending December 31, 2006 and 2005.

The following tables summarize the financial information for ANGT for the periods noted:

Summarized Balance Sheets

	As of December 31, 2006 (unaudited) (Thousands)	2005
Current assets	$ 5,085	$ 12,228
Noncurrent assets	188,742	206,085
Total assets	$ 193,827	$ 218,313
Current liabilities	$ 3,194	$ 17
Stockholders equity	190,633	218,296
Total liabilities and stockholders equity	$ 193,827	$ 218,313

Summarized Statements of Income

	Year Ended December 31, 2006 (unaudited) (Thousands)	2005	2004
Revenues	$ 94,477	$ 108,307	$ 89,513
Costs and expenses applicable to revenues			
Net revenues	94,477	108,307	89,513
Operating expenses	43,056	39,601	39,462
Net income	$ 51,421	$ 68,706	$ 50,051

9. Investments, Available-For-Sale

As of December 31, 2006, the investments classified by the Company as available-for-sale consist of approximately $31.3 million of equity securities intended to fund plugging and abandonment and other liabilities for which the Company self-insures. Any unrealized gains or losses with respect to investments classified as available-for-sale are recognized within the Consolidated Balance Sheets as a component of equity, accumulated other comprehensive loss.

	December 31, 2006			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(Thousands)			
Corporate equity securities	$ 25,164	$ 6,106	$	$ 31,270
Total investments	$ 25,164	$ 6,106	$	$ 31,270

	December 31, 2005			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(Thousands)			
Corporate equity securities	$ 22,742	$ 2,452	$	$ 25,194
Total investments	$ 22,742	$ 2,452	$	$ 25,194

In May 2005, the three variable share forward transactions associated with Kerr-McGee shares were terminated as described in Note 3. The Company concurrently sold 4.3 million Kerr-McGee shares to its three counterparties and received $227.4 million in pre-tax net proceeds at an average price of $75.43 per share. In addition, the Company unconditionally tendered 1.7 million Kerr-McGee shares at $85.00 per share to Kerr-McGee in connection with Kerr-McGee s Dutch auction tender offer to purchase its own shares. Accordingly, as a result of its tender of shares, the Company received approximately $49.0 million in pre-tax proceeds on the sale of approximately 0.6 million shares. These transactions resulted in pre-tax gains to the Company totaling $34.2 million, net of collar termination costs.

In various transactions during 2005, the Company sold its remaining approximately 2.1 million Kerr-McGee shares for total pre-tax proceeds of $184.1 million. The sale of these shares resulted in pre-tax gains to the Company totaling $76.1 million. The Company has no further interest or ownership in any Kerr-McGee shares.

The Company recorded pre-tax dividend income, net of payments to the counterparties for the aforementioned collars, of $1.2 million and $3.1 million for the years ended December 31, 2005 and 2004, respectively. This dividend income is recorded in other income, net on the Statements of Consolidated Income.

Under the terms of the merger agreement between Westport and Kerr-McGee, the Company received 0.71 shares of Kerr-McGee for each Westport share owned, or 8.2 million shares of Kerr-McGee, in the second quarter of 2004. Accordingly, the Company recognized a gain of $217.2 million on the exchange of the Westport shares for Kerr-McGee shares in 2004.

Subsequent to the Kerr-McGee/Westport merger, the Company sold 0.8 million Kerr-McGee shares for pre-tax proceeds of $42.9 million in 2004. The sale resulted in the Company recognizing a gain of $3.0 million in 2004.

In 2004, the Company contributed approximately 0.4 million Kerr-McGee shares to Equitable Resources Foundation, Inc. This resulted in the Company recording a charitable foundation contribution expense of $18.2 million during 2004, with a corresponding one-time tax benefit of $6.8 million.

The Company utilizes the specific identification method to determine the cost of all investment securities sold.

10. Regulatory Assets

The following table summarizes the Company s regulatory assets, net of amortization, as of December 31, 2006 and 2005. 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, 2006 (Thousands)	2005
Deferred taxes	$ 59,932	$ 56,208
Delinquency Reduction Opportunity Program	3,006	5,049
Other postretirement benefits (SFAS No. 106)	15,590	8,626
Deferred purchase gas costs	54,062	50,472
Other	191	172
Total regulatory assets	132,781	120,527
Amounts classified as other current assets	54,062	50,472
Total long-term regulatory assets	$ 78,719	$ 70,055

The regulatory asset associated with deferred taxes primarily represents deferred income taxes recoverable through future rates once the taxes become current. The Company expects to recover the amortization of this asset through rates.

The regulatory asset associated with a Delinquency Reduction Opportunity Program at Equitable Gas relates to uncollectible accounts receivable resulting from unusually high natural gas prices and unseasonably cold weather experienced during the winter of 2000-2001. The regulatory asset was initially established based upon the Company s ability to recover these costs through a surcharge in rates. In 2002, the PA PUC issued an order approving a Delinquency Reduction Opportunity Program that gives incentives to low-income customers to make payments that exceed their current bill amount in order to receive additional credits from the Company intended to speed the reduction of the customer s delinquent balance. This program is funded through customer contributions and through the existing surcharge in rates.

Under the Equitrans (a subsidiary of the Company) rate case settlement, the Company began amortization of postretirement benefits other than pensions previously deferred as well as recognizing expenses for on-going postretirement benefits other than pensions, which are now subject to recovery from July 1, 2005 forward in the approved rates. The reduction in the Company s regulatory asset for amortization of postretirement benefits other than pensions previously deferred was approximately $1.4 million for the year ended December 31, 2006. In addition, as a part of the rate case settlement, the Company s regulatory asset was reduced approximately $1.3 million in 2006 for amortization of postretirement benefits other than pensions previously deferred and on-going postretirement benefits other than pensions for the period July 1, 2005 to December 31, 2005.

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize a benefit plan s funded status in its statement of financial position, measure a benefit plan s assets and obligations as of the end of the employer s fiscal year and recognize the changes in the benefit plan s funded status in other comprehensive income in the year in which the changes occur. SFAS No. 158 s requirement to recognize the funded status of a benefit plan and the new disclosure requirements were effective as of December 31, 2006. The Company recorded $9.8 million as a regulatory asset for Equitrans other postretirement benefits in applying SFAS No. 158 as of December 31, 2006. The Company believes the future recovery of the unfunded status of the Equitrans other postretirement benefits is probable in accordance with the requirements of SFAS No. 71.

The following regulatory assets do not earn a return on investment: deferred taxes, Delinquency Reduction Opportunity Program and other postretirement benefits (SFAS No. 106). The associated remaining recovery period for the regulatory assets associated with both the Delinquency Reduction Opportunity Program and other postretirement benefits is four years at December 31, 2006. The associated remaining recovery period for the regulatory assets associated with deferred taxes is variable depending on the life of the book/tax difference generating the deferred item.

11. Short-Term Loans

On October 27, 2006, the Company entered into a $1.5 billion, five-year revolving credit agreement, which replaced the Company s previous $1 billion, five-year revolving credit agreement. On December 15, 2006, the maturity date was extended to October 26, 2011 pursuant to its terms. Additionally, the Company may request two one-year extensions of the stated maturity date. The revolving credit agreement may be used for working capital, capital expenditures, share repurchases and other purposes including support of the Company s commercial paper program. Subject to certain terms and conditions, the Company may, on a one time basis, request that the lender s commitments be increased to an aggregate amount of up to $2.0 billion.

The Company is not required to maintain compensating bank balances. The Company s debt issuer credit ratings, as determined by either Standard & Poor s or Moody s on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with its lines of credit in addition to the interest rate charged by the counterparties on any amounts borrowed against the lines of credit; the lower the Company s debt credit rating, the higher the level of fees and borrowing rate. As of December 31, 2006, the Company had not borrowed any amounts against these lines of credit. Commitment fees averaging one-seventeenth and one-thirteenth of one percent in 2006 and 2005, respectively, were paid to maintain credit availability.

Short-term loans were comprised of commercial paper balances of $136.0 million and $365.3 million with weighted average annual interest rates of 5.45% and 4.40% as of December 31, 2006 and 2005, respectively. The maximum amount of outstanding short-term loans at any time during the year was $467.5 million in 2006 and $631.5 million in 2005. The average daily balance of short-term loans outstanding over the course of the year was approximately $126.0 million and $309.6 million at weighted average annual interest rates of 4.63% and 3.48% during 2006 and 2005, respectively.

12. Long-Term Debt

	December 31, 2006	**2005**
	(Thousands)	
5.15% notes, due March 1, 2018	$ 200,000	$ 200,000
5.15% notes, due November 15, 2012	200,000	200,000
5.00% notes, due October 1, 2015	150,000	150,000
7.75% debentures, due July 15, 2026	115,000	115,000
Medium-term notes:		
8.5% to 9.0% Series A, due 2009 thru 2021	50,500	53,500
7.3% to 7.6% Series B, due 2013 thru 2023	30,000	30,000
6.8% to 7.6% Series C, due 2007 thru 2018	18,000	18,000
	763,500	766,500
Less debt payable within one year	10,000	3,000
Total long-term debt	$ 753,500	$ 763,500

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, in the event that the Company s debt rating changes, this event would not trigger a default under the indentures and other agreements governing the Company s indebtedness.

Aggregate maturities of long-term debt are $10.0 million in 2007, $0 in 2008, $4.3 million in 2009, $0 in 2010 and $6.0 million in 2011.

13. Pension and Other Postretirement Benefit Plans

During the fourth quarter of 2006, the Company recognized a settlement expense of approximately $3.3 million, comprised of $2.7 million for pension benefits and $0.6 million for other postretirement benefits, for an early retirement program, which was accounted for under SFAS No. 88 *and SFAS No. 106. This* settlement expense was primarily the result of special termination benefits. Under this settlement, the affected employees were provided the option to either receive the lump-sum value or an insured monthly annuity of their pension benefit or roll over the lump-sum value of their pension benefit to the Company s defined contribution plan. The $3.3 million settlement expense is recorded as a gathering and compression expense included within operating expense of the Equitable Supply business segment (see Note 2). As a result of this settlement, the Company s projected benefit obligation decreased by approximately $1.4 million.

During 2006, the Company made certain retiree medical plan design changes, which were accounted for under SFAS No. 106, that decreased the Company s other postretirement benefits plan benefits obligation by approximately $10.2 million. These design changes included a decrease in the Company s capped contribution per retiree and the elimination of certain retiree benefits.

During 2005, the Company settled its pension obligation with the United Steelworkers of America, Local Union 12050 representing 182 employees. As a result of this settlement, which was accounted for under SFAS No. 88, the Company recognized a settlement expense of $12.1 million during 2005. During the fourth quarter of 2005, the Company settled its pension obligation with certain non-represented employees. As a result of this settlement, which was accounted for under SFAS No. 88, the Company recognized a settlement expense of approximately $2.4 million in 2005. These settlement expenses were primarily the result of accelerated recognition of unrecognized losses. Under these settlements, the affected employees were provided the option to either roll over the lump-sum value of their pension benefit to the Company s defined contribution plan or to receive an insured monthly annuity benefit at the time they retire. Additionally, $14.3 million of these pension settlement expenses are recorded as a selling, general and administrative expense within operating expense of the Equitable Utilities business segment, and $0.2 million is a gathering and compression expense included within operating expense of the Equitable Supply business segment (see Note 2). As a result of these settlements, the Company s projected benefit obligation decreased by approximately $13.9 million.

All other non-represented employees are participants in a defined contribution plan.

Effective December 31, 2004, the Company settled the pension obligation of those non-represented employees (cash balance participants) whose benefits were frozen as of December 31, 2003. As a result of this settlement, the Company recognized a one-time settlement expense of $13.4 million in 2004, which was primarily the result of accelerated recognition of previously deferred unrecognized losses. The pension settlement expense in 2004 is recorded as an unallocated expense in deriving total operating income for segment reporting purposes (see Note 2). As a result of this settlement, the Company s projected benefit obligation decreased by approximately $19.6 million.

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize a benefit plan s funded status in its statement of financial position, measure a benefit plan s assets and obligations as of the end of the employer s fiscal year and recognize the changes in the benefit plan s funded status in other comprehensive income in the year in which the changes occur. SFAS No. 158 s requirement to recognize the funded status of a benefit plan and the new disclosure requirements were effective as of December 31, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. The incremental effect of applying SFAS No. 158 in the Company s statement of financial position as of December 31, 2006 is as follows:

	December 31, 2006 (Thousands) Before application of SFAS No. 158	Adjustments	After application of SFAS No. 158
Incremental effect of applying SFAS No. 158 on individual line items in the statement of financial position:			
Regulatory assets	$ 68,908	$ 9,811	$ 78,719
Other assets	34,841	(1,863)	32,978
Total other assets	103,749	7,948	111,697
Total assets	3,248,963	7,948	3,256,911
Other current liabilities	144,525	5,678	150,203
Total current liabilities	1,074,101	5,678	1,079,779
Deferred income taxes and investment tax credits	348,729	(10,717)	338,012
Pension and other postretirement benefits liabilities	22,950	27,997	50,947
Accumulated other comprehensive loss	(299,292)	(15,010)	(314,302)
Total common stockholders equity	961,290	(15,010)	946,280
Total liabilities and common stockholders equity	3,248,963	7,948	3,256,911

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

	Pension Benefits 2006 (Thousands)	2005	Other Benefits 2006	2005
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 82,153	$ 116,255	$ 54,257	$ 55,673
Service cost	430	899	553	541
Interest cost	4,389	5,891	2,899	3,168
Amendments			(10,180)	1,248
Actuarial loss	5,325	7,883	5,317	675
Benefits paid	(7,637)	(7,605)	(6,291)	(7,048)
Curtailments	227	1,048	410	
Settlements	(4,181)	(42,218)		
Special termination benefits	1,416		179	
Benefit obligation at end of year	$ 82,122	$ 82,153	$ 47,144	$ 54,257

	Pension Benefits 2006 (Thousands)	2005	Other Benefits 2006	2005
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 75,079	$ 100,917	$	$
Gain recognized at beginning of year		41		
Actual gain on plan assets	7,593	3,580		
Employer contributions	1,751	20,364		
Benefits paid	(7,637)	(7,605)		
Settlements	(4,170)	(42,218)		
Fair value of plan assets at end of year	$ 72,616	$ 75,079	$	$
Funded status at end of year	$ (9,506)	$ (7,074)	$ (47,144)	$ (54,257)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$	$	$ (5,678)	$
Noncurrent liabilities	(9,506)	(7,074)	(41,466)	(13,796)
Net amount recognized	$ (9,506)	$ (7,074)	$ (47,144)	$ (13,796)
Amounts recognized in accumulated other comprehensive loss consist of, net of tax:				
Net loss	$ 16,390	$ 15,366	$ 17,945	$
Net prior service cost (credit)	727		(3,662)	
Net amount recognized	$ 17,117	$ 15,366	$ 14,283	$

The accumulated benefit obligation for all defined benefit pension plans was $82.1 million and $82.2 million at December 31, 2006 and 2005, respectively. The Company uses a December 31 measurement date for its defined benefit pension and other postretirement plans.

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

	Pension Benefits 2006 (Thousands)	2005	2004	Other Benefits 2006	2005	2004
Components of net periodic benefit cost:						
Service cost	$ 430	$ 899	$ 1,590	$ 553	$ 541	$ 483
Interest cost	4,389	5,891	6,970	2,899	3,168	3,273
Expected return on plan assets	(6,132)	(8,032)	(9,828)			
Amortization of prior service cost	370	766	940	(137)	(42)	(42)
Recognized net actuarial loss	1,069	867	745	2,146	2,299	2,000
Settlement loss and special termination benefits (a)	2,348	15,713	13,733	179		
Curtailment loss	602	2,648	2,434	410		
Net periodic benefit cost	$ 3,076	$ 18,752	$ 16,584	$ 6,050	$ 5,966	$ 5,714

(a) The 2005 settlement loss and special termination benefits includes $10.4 million of loss recognition for the settlement of the Steelworkers pension benefit obligation and $1.3 million of loss associated with the non-represented employees portion of the pension benefit obligation which was settled during the fourth quarter of 2005. The 2004 settlement loss and special termination benefits includes $11.0 million of loss recognition associated with the settlement of the cash balance participants pension benefit obligation at December 31, 2004, for those non-represented employees whose benefits under the pension plan were frozen in 2003.

Under the Equitrans rate case settlement, the Company began amortization of post-retirement benefits other than pensions previously deferred as well as recognizing expenses for on-going post-retirement benefits other than pensions, which are now subject to recovery from July 1, 2005 forward in the approved rates. Expenses recognized by the Company for the year ended December 31, 2006 for amortization of post-retirement benefits other than pensions previously deferred and on-going post-retirement benefits other than pensions were approximately $1.4 million and $1.2 million, respectively. In addition, as a part of the rate case settlement, the Company recognized expenses for year ended December 31, 2006 of approximately $1.3 million for amortization of post-retirement benefits other than pensions previously deferred and on-going post-retirement benefits other than pensions for the period July 1, 2005 to December 31, 2005.

	Pension Benefits			**Other Benefits**		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
	(Thousands)					
Other changes in plan assets and benefit obligations recognized in other comprehensive loss, net of tax:						
Net loss (gain)	$ 1,024	$ (4,325)	$ (5,841)	$ 17,945	$	$
Net prior service cost (credit)	727			(3,662)		
Total recognized in other comprehensive income, net of tax	1,751	(4,325)	(5,841)	14,283		
Total recognized in net periodic benefit cost and other comprehensive income, net of tax	$ 4,827	$ 14,427	$ 10,743	$ 20,333	$ 5,966	$ 5,714

The estimated net loss and net prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost over the next fiscal year are $1.4 million and $0.3 million, respectively. The estimated net loss and net prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost over the next fiscal year are $2.3 million and ($0.8 million).

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

	Pension Benefits		**Other Benefits**	
	2006	**2005**	**2006**	**2005**
Discount rate	5.75 %	5.75 %	5.75 %	5.75 %
Expected return on plan assets	8.25 %	8.25 %	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 that it relates to based upon information available to the Company at that time, including the plans investment mix and the forecasted rates of return on these types of securities. 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 in accordance with SFAS No. 87. The expected rate of return determined as of January 1, 2007 totaled 8.25%. This assumption will be used to derive the Company s 2007 net periodic benefit cost. The rate of compensation increase is no longer applicable in determining future benefit obligations as a result of the conversion of certain non-represented employees to a defined contribution plan in 2003 as previously discussed. Pension expense increases as the expected long-term rate of rate of return decreases or if the discount rate is lowered. Lowering the expected long-term rate of return by 0.5% or lowering the discount rate by 0.5% as of December 31, 2006, would not have a significant impact on pension expense for 2007.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2007 is 10.0% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.0% in 2012.

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 (Thousands)			One-Percentage-Point Decrease (Thousands)		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Increase (decrease) to total of service and interest cost components	$ 115	$ 91	$ 108	$ (109)	$ (90)	$ (104)
Increase (decrease) to postretirement benefit obligation	$ 1,071	$ 2,030	$ 1,751	$ (1,000)	$ (1,897)	$ (1,659)

The Company s pension asset allocation at December 31, 2006 and 2005 and target allocation for 2007 by asset category are as follows:

Asset Category	Target Allocation 2007	Percentage of Plan Assets at December 31, 2006	2005
Domestic broadly diversified equity securities	50% - 70%	50%	54%
Fixed income securities and inflation hedge securities	30% - 45%	36%	38%
International broadly diversified equity securities	5% - 15%	11%	7%
Other	0% - 15%	3%	1%
		100%	100%

The investment activities of the Company s pension plan are supervised and monitored by the Company s Benefits Investment Committee. The Benefits Investment Committee has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the Benefits Investment Committee are to minimize high levels of risk at the total pension investment fund level. The Benefits Investment Committee monitors the actual 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 $1.8 million and $20.4 million to its pension plan during 2006 and 2005, respectively, as a result of the previously described settlements. The Company expects to make cash contributions of approximately $1.0 million to its pension plan during 2007. The Company was not required to, and consequently did not make any contribution to its pension plans during the year ended December 31, 2004.

The following benefit payments, which reflect expected future service, are expected to be paid during each of the next five years and the five years thereafter: $10.1 million in 2007; $7.3 million in 2008; $7.4 million in 2009; $6.8 million in 2010; $7.3 million in 2011; and $33.5 million in the five years thereafter.

Expense recognized by the Company related to its 401(k) employee savings plans totaled $5.2 million in 2006, $5.1 million in 2005 and $4.5 million in 2004.

14. Common Stock and Earnings Per Share

At December 31, 2006, shares of Equitable s authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	13,194
Stock compensation plans	14,663
Total	27,857

Earnings Per Share

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

	Years Ended December 31,		
	2006	2005	2004
	(Thousands, except per share amounts)		
Basic earnings per common share:			
Income from continuing operations	$ 216,025	$ 258,574	$ 298,790
Income (loss) from discontinued operations, net of tax	4,261	1,481	(18,936)
Net income applicable to common stock	$ 220,286	$ 260,055	$ 279,854
Average common shares outstanding	120,124	121,099	123,364
Basic earnings per common share	$ 1.83	$ 2.15	$ 2.27
Diluted earnings per common share:			
Income from continuing operations	$ 216,025	$ 258,574	$ 298,790
Income (loss) from discontinued operations, net of tax	4,261	1,481	(18,936)
Net income applicable to common stock	$ 220,286	$ 260,055	$ 279,854
Average common shares outstanding	120,124	121,099	123,364
Potentially dilutive securities:			
Stock options and awards (a)	1,989	2,616	2,838
Total	122,113	123,715	126,202
Diluted earnings per common share	$ 1.80	$ 2.10	$ 2.22

(a) Options to purchase 53,093 shares of common stock were not included in the computation of diluted earnings per common share for 2006 because the options exercise prices were greater than the average market prices of the common shares. There were no antidilutive options for 2005 or 2004.

15. Accumulated Other Comprehensive Loss

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

	2006	2005
	(Thousands)	
Net unrealized loss from hedging transactions	$ (286,871)	$ (741,804)
Unrealized gain on available-for-sale securities	3,969	1,570
Pension and other post-retirement benefits adjustment	(31,400)	(15,366)
Accumulated other comprehensive loss	$ (314,302)	$ (755,600)

16. Share-Based Compensation Plans

The Company adopted SFAS No. 123R effective January 1, 2006, using the modified prospective method. Under the modified prospective method, compensation cost is recognized beginning with the effective date and prior period results are not restated. As such, compensation cost related to all share-based awards, including non-qualified stock options, was recorded as selling, general and administrative expense in the Company s Statement of Consolidated Income for the year ended December 31, 2006. The compensation cost that has been charged to expense for all of the Company s share-based compensation arrangements, described below, was $26.6 million, $48.4 million, and $30.8 million for the years ended December 31, 2006, 2005, and 2004, respectively.

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123R to employee share-based awards for the years ended December 31, 2005 and December 31, 2004.

	Year Ended December 31, 2005 (Thousands)			**Year Ended December 31, 2004**		
Net income, as reported	$	260,055		$	279,854	
Add: Gross share-based employee compensation expense included in reported net income	48,363			30,763		
Deduct: Income tax benefit from share-based employee compensation expense included in reported net income	(16,182		)	(10,389		)
Deduct: Total share-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(33,693		)	(24,575		)
Pro forma net income	$	258,543		$	275,653	
Earnings per share:						
Basic, as reported	$	2.15		$	2.27	
Basic, pro forma	$	2.13		$	2.23	
Diluted, as reported	$	2.10		$	2.22	
Diluted, pro forma	$	2.09		$	2.18	

Adoption of SFAS No. 123R had the effect of reducing operating income and income from continuing operations before income taxes by $1.0 million, and net income by $0.6 million or less than $0.01 per basic and diluted share, for the year ended December 31, 2006. Prior to the adoption of SFAS No. 123R, the Company presented all tax benefits for deductions resulting from the exercise of share-based awards as cash flows from operating activities in its Statements of Condensed Consolidated Cash Flows. SFAS No. 123R requires the benefits of tax deductions in excess of recognized compensation expense to be reported as a cash flow from financing activities, rather than as a cash flow from operating activities. This requirement reduced cash flows from operating activities and increased cash flows from financing activities by $15.7 million for the year ended December 31, 2006. Total net cash flows were not impacted by the adoption of SFAS No. 123R.

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2006, 2005, and 2004, was $34.9 million, $25.0 million and $26.9 million, respectively. The actual tax benefits realized for tax deductions from share-based payment arrangements for the years ended December 31, 2006, 2005, and 2004, were $18.9 million, $28.0 million and $13.6 million, respectively.

The Company typically funds restricted share obligations from treasury stock at the date of grant and has a policy of issuing shares from treasury stock to satisfy option exercises.

Executive Performance Incentive Programs

In February 2005, the Compensation Committee of the Board of Directors adopted the 2005 Executive Performance Incentive Program (2005 Program) under the 1999 Long-Term Incentive Plan. The 2005 Program was established to provide additional incentive benefits to retain executive officers and certain other employees of the Company to further align the interests of the persons primarily responsible for the success of the Company with the interests of the shareholders. A total of 1,029,800 stock units granted under the 2005 Program are outstanding as of December 31, 2006. No additional units may be granted. The vesting of these stock units will occur on December 31, 2008, contingent upon a combination of the level of total shareholder return relative to the 29 peer companies identified below and the Company s average absolute return on total capital during the four-year performance period. As a result, zero to 2,574,500 units (250% of the units outstanding) may be distributed in cash or stock. The Company anticipates, based on current estimates, that a certain level of performance will be met and has expensed a ratable estimate of the units accordingly. The 2005 Program expense for the years ended December 31, 2006 and 2005 was $21.1 million and $22.5 million, respectively, and is classified as selling, general and administrative expense in the Statements of Consolidated Income. A portion of the 2005 Program expense is included as an unallocated expense in deriving total operating income for segment reporting purposes. See Note 2.

The current peer companies for the 2005 Program are as follows:

AGL Resources Inc.	MDU Resources, Inc.	Questar Corp.
Atmos Energy Corp.	National Fuel Gas Co.	Sempra Energy
Cascade Natural Gas Co.	New Jersey Resources Corp.	Southern Union Co.
CMS Energy Corp.	NICOR, Inc.	Southwest Gas Corp.
Dynegy Inc.	NiSource Inc.	Southwestern Energy Co.
El Paso Corp.	Northwest Natural Gas Co.	UGI Corp.
Energen Corp.	OGE Energy Corp.	Westar Energy, Inc.
Keyspan Corp.	ONEOK, Inc.	WGL Holdings, Inc.
Kinder Morgan Inc.	Peoples Energy Corp.	Williams Industries, Inc.
The Laclede Group, Inc.	Piedmont Natural Gas Co., Inc.	

The vesting of performance-based stock units granted under the 2003 Executive Performance Incentive Program (2003 Program) occurred on December 30, 2005, after the ordinary close of the performance period and resulted in approximately 1.3 million units (167% of the award) being distributed in cash on that date. This payment totaled $51.0 million. The 2003 Program expense for the years ended December 31, 2005 and 2004 was $21.3 million and $19.2 million, respectively, and is classified as selling, general and administrative expense.

In the first quarter of 2005, the Company paid out the 552,000 performance-based stock units that vested December 31, 2004, under the Company s 2002 Executive Performance Incentive Program (2002 Program). This payment totaled $16.7 million. The 2002 Program expense for the year ended December 31, 2004 was $7.0 million and is classified as selling, general and administrative expense.

Restricted Stock Awards

The Company granted 112,700, 138,400, and 291,100 restricted stock awards during the years ended December 31, 2006, 2005, and 2004, respectively, to key executives of the Company. The majority of these awards will be fully vested at the end of the three-year period commencing the date of grant. The fair value of each share is determined based on the market price of the Company s common stock on 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 $36.11, $33.07, and $21.88, for the years ended December 31, 2006, 2005, and 2004, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2006, 2005, and 2004 was $1.5 million, $1.8 million and $0.1 million, respectively. Compensation expense recorded by the Company related to restricted stock awards was $3.5 million, $3.4 million and $3.8 million for the years ended December 31, 2006, 2005, and 2004, respectively.

As of December 31, 2006, there was $5.3 million of total unrecognized compensation cost related to nonvested restricted stock awards. That cost is expected to be recognized over a weighted average period of approximately 10.1 months.

A summary of restricted stock activity as of December 31, 2006, and changes during the year then ended, is presented below:

Restricted Stock	**Non-Vested Shares**	**Weighted Average Fair Value**	**Weighted Average Remaining Contractual Term (months)**	**Aggregate Fair Value**
Outstanding at January 1, 2006	520,435	$ 22.82		$ 11,877,895
Granted	112,700	$ 36.11		$ 4,069,115
Vested	(77,115)	$ 18.91		$ (1,458,367)
Forfeited	(12,680)	$ 28.86		$ (365,928)
Outstanding at December 31, 2006	543,340	$ 25.99	10.1	$ 14,122,715

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, 2006, 2005, and 2004. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the historical dividend yield of the Company s stock. Expected volatilities are based on historical volatility of the Company s stock. The expected term of options granted represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

	Years Ended December 31, 2006	**2005**	**2004**
Risk-free interest rate	4.51% to 5.04%	3.74% to 4.34%	1.95% to 4.34%
Dividend yield	2.34% to 2.38%	2.75% to 2.83%	2.47% to 2.97%
Volatility factor	.212 to .226	.258 to .262	.214 to .263
Expected term	7 years	7 years	7 years

The Company granted 84,935, 68,898, and 126,858 stock options during the years ended December 31, 2006, 2005, and 2004, respectively, all of which comprised options granted for reload rights associated with previously-awarded options. The weighted average grant date fair value of these reload option grants was $9.43, $7.65, and $4.94 for the years ended December 31, 2006, 2005, and 2004, respectively. The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $52.2 million, $48.1 million and $22.2 million, respectively.

As of December 31, 2006, there was no unrecognized compensation cost related to outstanding nonvested stock options as all outstanding options were fully vested.

A summary of option activity as of December 31, 2006, and changes during the year then ended, is presented below:

Nonqualified Stock Options	**Shares**	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Term**	**Aggregate Intrinsic Value**
Outstanding at January 1, 2006	5,110,421	$ 16.32		
Granted	84,935	$ 37.61		
Exercised	(2,228,966)	$ 16.41		
Forfeited	(4,716)	$ 17.46		
Outstanding at December 31, 2006	2,961,674	$ 16.86	4.8 years	$ 73,727,195
Exercisable at December 31, 2006	2,961,674	$ 16.86	4.8 years	$ 73,727,195

Nonemployee Directors Stock Incentive Plan

At December 31, 2006, 160,904 options were outstanding under the 1999 Nonemployee Directors Stock Incentive Plan at prices ranging from $6.59 to $29.67 per share, and 537,200 options had been exercised under this plan since plan inception. The exercise price for each award is equal to the market price of the Company s common stock on the date of grant. Each option is subject to time-based vesting provisions and expires 5 to 10 years after date of grant.

The Company has also historically granted to non-employee directors stock units which vested upon award. The value of the stock units will be paid in cash on the earlier of the director s death or retirement from the Company s Board of Directors. A total of 72,960 non-employee director stock units were outstanding as of December 31, 2006. A total of 18,000, 18,000, and 21,120 stock units were granted to non-employee directors during the years ended December 31, 2006, 2005, and 2004, respectively.

17. Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, as well as short-term loans, approximates fair value due to the short maturity of the instruments. The fair value of the available-for-sale securities is estimated based on quoted market prices for those investments.

The estimated fair value of long-term debt described in Note 12 at December 31, 2006 and 2005 was $786.0 million and $816.8 million, respectively. The fair value was estimated based on discounted values using a current discount rate reflective of the remaining maturity.

The estimated fair value of liabilities for derivative instruments described in Note 3, excluding trading activities which are marked-to-market, was a $129.7 million asset and a $544.4 million liability at December 31, 2006, and a $36.0 million asset and a $1.2 billion liability at December 31, 2005.

18. Concentrations of Credit Risk

Revenues and related accounts receivable from the Equitable Supply segment s operations are generated primarily from the sale of produced natural gas and limited amounts of crude oil to certain marketers, Equitable Energy, LLC (an affiliate), other Appalachian Basin purchasers and utility and industrial customers located mainly in the Appalachian area; the sale of produced natural gas liquids to a gas processor in Kentucky; and gathering of natural gas in Kentucky, Virginia, Pennsylvania and West Virginia.

Equitable Utilities distribution operating revenues and related accounts receivable are generated from state-regulated utility natural gas sales and transportation to approximately 274,000 residential, commercial and industrial customers located in southwestern Pennsylvania, northern West Virginia and eastern Kentucky. The Pipeline operations include FERC-regulated interstate pipeline transportation and storage service for the affiliated utility, Equitable Gas Company (Equitable Gas), as well as other utility and end-user customers located in the northeastern United States. The unregulated marketing operations provide 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.

Under previous state regulations, Equitable Gas was required to provide continuous natural gas service to residential customers during the winter heating season. The Responsible Utility Customer Protection Act (Act 201), which became effective in Pennsylvania on December 14, 2004, established new procedures for utilities regarding collection activities with respect to deposits, payment plans and terminations for residential customers and is intended to help utility companies collect amounts due from customers. As a result of Act 201, the Company is permitted to send winter termination notices to customers whose household income exceeds 250% of the federal poverty level and complete customer terminations without approval from the PA PUC.

Approximately 73% and 69% of the Company s accounts receivable balance as of December 31, 2006 and 2005, respectively, represent amounts due from marketers. The Company manages the credit risk of sales to marketers by limiting its dealings to those marketers who meet the Company s criteria for credit and liquidity strength and by proactively 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, 2006 and 2005.

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. NYMEX-traded futures contracts have minimal credit risk because futures exchanges are the counterparties. The Company manages the credit risk of the other derivative contracts by limiting dealings to those counterparties who meet the Company s criteria for credit and liquidity strength. Some of the Company s agreements with counterparties contain netting provisions in order to mitigate the Company s short-term and long-term exposure in the event of default.

The Company is not aware of any significant credit risks that have not been recognized in provisions for doubtful accounts.

19. Commitments and Contingencies

The Company has annual commitments of approximately $37.8 million for demand charges under existing long-term contracts with pipeline suppliers for periods extending up to ten years as of December 31, 2006, which relate to natural gas distribution and production operations. However, the Company believes that approximately $26.4 million of these costs are recoverable in customer rates.

In the ordinary course of business, various legal 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 has established reserves for pending litigation, which it believes are adequate, 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 of the Company.

In June 2006, the West Virginia Supreme Court of Appeals issued a decision involving interpretation of certain types of oil and gas leases of an unrelated party, in which a class of royalty owners in the state of West Virginia filed a lawsuit claiming that the defendant in the case underpaid royalties by deducting certain post-production costs not permitted by such types of leases and not paying a fair value for the gas produced from the royalty owners leases. In January 2007, the jury in the aforementioned case returned a verdict in favor of the plaintiff royalty owners, awarding the plaintiffs significant compensatory and punitive damages for the alleged underpayment of royalties. While the defendant plans to appeal the verdict, this decision may ultimately impact other royalty interest rights in West Virginia. Claims have been brought against others in the oil and gas industry, including the Company. The actions against the Company are in the early stages of proceedings. The Company believes that the claims and facts decided in the unrelated lawsuit can be differentiated from those asserted against the Company. Nevertheless, the Company has reviewed its West Virginia royalty agreements and established a reserve it believes to be appropriate.

The Company is subject to various federal, state and local environmental and environmentally related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may in certain instances result in assessment of fines. The Company has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. The estimated costs associated with identified situations that require remedial action are accrued. However, certain costs are deferred as regulatory assets when recoverable through regulated rates. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material effect on the Company s financial position or results of operations. The Company has identified situations that require remedial action for which approximately $1.8 million is included in other credits in the Consolidated Balance Sheet as of December 31, 2006.

Operating lease rentals for office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately $6.0 million in 2006, $4.9 million in 2005 and $4.2 million in 2004. Future lease payments under non-cancelable operating leases as of December 31, 2006 totaled $56.0 million (2007 - $6.8

million, 2008 - $6.0 million, 2009 - $4.3 million, 2010 - $3.7 million, 2011 - $2.4 million and thereafter - $32.8 million).

20. Guarantees

NORESCO Guarantees

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain of NORESCO s obligations previously issued to the purchasers of NORESCO s receivables. The guaranteed obligations of NORESCO include certain receivable sales and customer contracts, for which the undiscounted maximum aggregate payments that may be due is approximately $361 million as of December 31, 2006, extending at a decreasing amount for approximately 20 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, 2006 of approximately $123 million, of which approximately $107 million relates to work already completed under the associated contracts. In addition, approximately $116 million of these guarantee obligations will end or be terminated not later than December 30, 2010.

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.

The Company has determined that the likelihood it will be required to perform on these arrangements is remote and has not recorded any liabilities in its Consolidated Balance Sheet related to these guarantees.

Other Guarantees

In November 1995, Equitable, through a subsidiary, guaranteed a tax indemnification to the limited partners of Appalachian Basin Partners, LP (ABP) for any potential tax losses resulting from a disallowance of the nonconventional fuels tax credits, if certain representations and warranties of the Company were not true. The Company guaranteed the tax indemnification until the tax statute of limitations closes. The Company does not have any recourse provisions with third parties or any collateral held by third parties associated with this guarantee that could be liquidated to recover amounts paid, if any, under the guarantee. As of December 31, 2006, the maximum potential amount of future payments the Company could be required to make is estimated to be approximately $46 million. The Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN 45, and has not been modified subsequent to issuance. Additionally, based on the status of the Company s IRS examinations, the Company has determined that any potential loss from this guarantee is remote.

In June 2000, Equitable sold certain properties and, through a subsidiary, guaranteed a tax indemnification to the buyer for any potential tax losses resulting from a disallowance of the nonconventional fuels tax credits, if certain representations and warranties of the Company were not true. The Company guaranteed the tax indemnification until the tax statute of limitations closed. The Company had not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN 45 and had not been modified subsequent to issuance. During 2006, the statue of limitations relating to the years in which the tax indemnification applied elapsed and as such, the Company no longer has any potential obligation under this guarantee.

In December 2000, the Company entered into a transaction with ANGT by which natural gas producing properties located in the Appalachian Basin region of the United States were sold. ANGT manages the assets and produces, markets, and sells the related natural gas from the properties. Appalachian NPI, LLC (ANPI) contributed cash to ANGT. The assets of ANPI, including its interest in ANGT, collateralize ANPI s debt. The Company provided ANPI with a liquidity reserve guarantee secured by the fair market value of the assets purchased by ANGT. This guarantee is subject to certain restrictions that limit the amount of the guarantee to the calculated present value of the project s future cash flows from the preceding year-end until the termination date of the agreement. The agreement also defines events of default, use of proceeds and demand procedures. The Company has received a market-based fee for providing the guarantee. As of December 31, 2006, the maximum potential amount of future payments the Company could be required to make under the liquidity reserve guarantee is estimated to be approximately $50 million. The Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN 45 and has not been modified subsequent to issuance.

21. Office Consolidation / Impairment Charges

In May 2005, the Company completed the relocation of its corporate headquarters and other operations to a newly constructed office building located at the North Shore in Pittsburgh. The relocation resulted in the early termination of several operating leases and the early retirement of assets and leasehold improvements at several locations. In accordance with SFAS No. 146, the Company recognized a loss of $5.3 million on the early termination of operating leases during 2005 for facilities deemed to have no economic benefit to the Company. The Company also recognized a loss on the impairment of assets of $2.5 million during 2005 in accordance with SFAS No. 144 associated with the office consolidations.

During the second quarter of 2006, the Company began to utilize certain of the leased space previously deemed to have no economic benefit to the Company to make space available for the pending acquisition of The Peoples Natural Gas Company and Hope Gas, Inc. transition planning activities. The Company reversed approximately $2.4 million of the associated early termination liability for these leases during the second quarter of 2006. Additionally, the Company recorded a $0.5 million reduction in the early termination liability during the second quarter of 2006 resulting from a revision of the amount of estimated cash flows for one of its operating leases.

22. Other Items

In June 2004, the Company amended its only remaining prepaid natural gas contract, which was viewed as debt by the rating agencies. The amendment required the Company to repay the net present value of the portion of the prepayment related to the undelivered quantities of natural gas in the original contract. The Company repaid the counterparty $36.8 million, removed the prepaid forward sale from the balance sheet and recorded a loss of $5.5 million in other income, net in the Statement of Consolidated Income for the year ended December 31, 2004, reflecting the difference between the net present value of the underlying quantities and the remaining unamortized balance recorded as deferred revenue.

In 2004, the Company settled a disputed property insurance coverage claim involving Kentucky West Virginia Gas Company, LLC, which is a part of the Equitable Supply operating segment. As a result of the settlement, the Company recognized income of approximately $6.1 million in 2004, which is included in other income, net, in the Statement of Consolidated Income for the year ended December 31, 2004.

23. Interim Financial Information (Unaudited)

The following quarterly summary of operating results reflects variations due primarily to the seasonal nature of the Company s utility business and volatility of natural gas and oil commodity prices. The 2005 quarterly results have been reclassified to reflect the Company s NORESCO business segment as discontinued operations for each period presented.

	March 31	June 30	September 30	December 31
	(Thousands, except per share amounts)			
2006 (a)				
Operating revenues	$ 430,119	$ 251,207	$ 232,801	$ 353,783
Net operating revenues	221,302	165,094	160,646	216,539
Operating income	127,657	74,119	61,135	109,612
Income from continuing operations	72,359	43,909	31,795	67,962
Income from discontinued operations, net of tax				4,261
Net income	72,359	43,909	31,795	72,223
Earnings per share of common stock:				
Income from continuing operations				
Basic	$ 0.61	$ 0.37	$ 0.26	$ 0.56
Diluted	$ 0.59	$ 0.36	$ 0.26	$ 0.56
Income from discontinued operations, net of tax				
Basic	$	$	$	$ 0.04
Diluted	$	$	$	$ 0.03
Net income				
Basic	$ 0.61	$ 0.37	$ 0.26	$ 0.60
Diluted	$ 0.59	$ 0.36	$ 0.26	$ 0.59

	March 31	June 30	September 30	December 31(b)
	(Thousands, except per share amounts)			
2005 (a)				
Operating revenues	$ 401,276	$ 230,194	$ 229,372	$ 392,882
Net operating revenues	212,545	154,277	163,416	212,317
Operating income	127,196	53,459	54,689	108,468
Income from continuing operations	74,791	57,953	45,811	80,019
Income (loss) from discontinued operations, net of tax	1,615	6,366	680	(7,180)
Net income	76,406	64,319	46,491	72,839
Earnings per share of common stock:				
Income from continuing operations				
Basic	$ 0.62	$ 0.48	$ 0.37	$ 0.67
Diluted	$ 0.60	$ 0.47	$ 0.37	$ 0.65
Income (loss) from discontinued operations, net of tax				
Basic	$ 0.01	$ 0.05	$ 0.01	$ (0.06)
Diluted	$ 0.01	$ 0.05	$	