EQUITABLE RESOURCES INC /PA/
Form 10-K
March 01, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

**ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2003

**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.)
One Oxford Centre, Suite 3300 Pittsburgh, Pennsylvania	**15219**
(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 Philadelphia Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange Philadelphia Stock Exchange

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

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 periods that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b 2 of the Exchange Act).

Yes ý No o

The aggregate market value of voting stock held by non-affiliates of the registrant as of January 30, 2004: **$2,706,419,135**

The number of shares outstanding of the issuer s classes of common stock as of January 30, 2004: **61,663,685**

DOCUMENTS INCORPORATED BY REFERENCE

Part III, a portion of Item 10 and Items 11, 12 and 14 are incorporated by reference from the Proxy Statement for the Company s Annual Meeting of Stockholders to be held on April 14, 2004, which Proxy Statement will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2003, except for the Performance Graph, Report of the Compensation Committee on Executive Compensation, and Report of the Audit Committee.

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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. Statements that do not relate strictly to historical or current facts are forward-looking and usually identified by the use of words such as should, anticipate, estimate, forecasts, approximate, expect, may, will, project, intend, plan 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 specifically include the expectations of future plans, objectives, cost savings, growth and anticipated financial and operational performance of the Company and its subsidiaries, including statements regarding the hedging of projected production and optimization of storage capacity through trading activities, the Company s identification of growth opportunities and its ability to execute its operational strategies, the intention to continue to be diluted as an owner of Westport Resources Corporation, the estimate of $29.0 million as the maximum amount payable under a guarantee in respect of the Appalachian Natural Gas Trust, the expectation of making no foreign investments in 2004, the belief that environmental expenditures will not be significantly different in nature or amount in the future and will not have a material effect on the Company s financial position or results of operations, the adequacy of legal reserves and therefore the belief that the ultimate outcome of any matter currently pending will not materially affect the financial position of the Company, the anticipation that dividends will continue to be paid on a regular quarterly basis, the belief that the implementation costs for the Equitable Gas customer information and billing system are appropriate, the estimated capital expenditures for each business segment and for corporate operations in 2004, the effect that a decrease of $0.10 in the NYMEX price of natural gas would have on the Company s earnings per diluted share and the fair market value of derivative contracts held by the Company for hedging or trading purposes, the likelihood of resolution of issues relating to the Company s Jamaican energy infrastructure project and the bankruptcy of ERI JAM, LLC, the strategic alternatives for the Company s 45% owned project in Panama, the expected cost to resolve noise issues at, expected cash flow being sufficient to pay debt service on, and the ability to obtain long-term power purchase agreements for, the Company s 50% owned project in Panama, the impact of new accounting pronouncements, the continuation of rate regulation which provides for the recovery of certain deferred costs, the estimated amount of cash contributions to the pension plan through 2006, the total pension expense to be recognized in 2004, the deductibility for Federal tax purposes of the capital loss on the Company s previous sale of its midstream operations, the anticipated changes in NORESCO backlog, the anticipated sale of NORESCO contracts, the expected drilling program, the likelihood that the U.S. Environmental Protection Agency rules regarding Spill Prevention, Control and Countermeasures will be modified and the cost to Company in the event they are not modified, the expectation that the lack of enabling legislation for performance contracting work is only temporary and the expectation that the passage of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 will reduce certain of the Company s medical costs. 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, the following: economic and competitive conditions, changes in energy commodity market conditions, increased competition in deregulated energy markets, weather conditions, the market value of the Company s common stock of Westport Resources Corporation, inflation rates, interest rates, changes in hedging positions, changes in Generally Accepted Accounting Principles, successful negotiation of labor contracts, amount of share repurchases by the Company, changing prices, legislative and regulatory changes, timely obtaining necessary or desirable regulatory approvals, the discretion vested in the trier of fact in pending litigation and in regulators in enforcing applicable regulation, financial market conditions, availability of financing, curtailments or disruptions in production and gathering, the ability to acquire and apply technology to Company operations, the ability to develop, finance, complete and operate energy infrastructure projects, the impact of asset impairment judgments and the ability to efficiently operate, gather, and market natural gas and oil, future business decisions, and other uncertainties, all of which are difficult to predict. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates. In addition, the drilling of development wells can involve significant risks, including those related to timing, success rates and cost overruns and these risks can be affected by lease and rig availability, complex geology and other factors. Furthermore, the Company cannot guarantee the absence of errors in input data, calculations, and formulas used in estimates, assumptions and forecasts. The Company undertakes no obligation to correct or update any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Item 1. Business

Equitable Resources, Inc. (Equitable Resources or Equitable or the Company) is an integrated energy company, with an emphasis on Appalachian area natural gas supply activities including production and gathering, natural gas distribution and transmission, and energy efficiency solutions nationally but primarily in the eastern and western coastal regions of the United States. The Company and its subsidiaries offer energy (natural gas, and a limited amount of crude oil and natural gas liquids) products and services to wholesale and retail customers through three business segments: Equitable Utilities, Equitable Supply and NORESCO. The Company and its subsidiaries had approximately 1,400 employees at the end of 2003.

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

The Company makes certain filings with the Securities and Exchange Commission (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, www.eqt.com, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC s Public Reference Room at 450 Fifth Street, N.W. Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at www.sec.gov. The Company s annual report to shareholders, press releases and recent analyst presentations are also available on its website.

Equitable Utilities

Equitable Utilities contains both regulated and nonregulated operations. The regulated group consists of the distribution and interstate pipeline operations, while the nonregulated group is involved in the non-jurisdictional marketing of natural gas, risk management activities for Equitable Utilities and Equitable Supply and the sale of energy-related products and services. Equitable Utilities generated approximately 40% of the Company s net operating revenues in 2003.

Natural Gas Distribution

Equitable Utilities distribution operations are carried out by Equitable Gas Company (Equitable Gas), a division of the Company. The service territory for Equitable Gas includes southwestern Pennsylvania, municipalities in northern West Virginia and field line sales (also referred to as farm tap service as the customer is served directly from a well or gathering pipeline) in eastern Kentucky. The distribution operations provide natural gas services to approximately 274,500 customers, comprising 255,500 residential customers and 19,000 commercial and industrial customers.

Equitable Gas natural gas supply portfolio includes short-term purchases (purchases to be delivered in one month or less), medium-term purchases (purchases to be delivered in less than one year but more than one month) and long-term purchases (purchases to be delivered in more than one year). These natural gas supply contracts are obtained from various sources including purchases from major and independent producers in the Southwest United States, purchases from local producers in the Appalachian area and purchases from gas marketers. Equitable Gas supply purchases include various pricing mechanisms, ranging from fixed prices to several different index related prices. These supply purchase contracts qualify as normal purchases and normal sales of natural gas.

Because most of its customers use natural gas for heating purposes, Equitable Gas revenues are seasonal, with approximately 70% of calendar year 2003 revenues occurring during the winter heating season (January March, November December). Significant quantities of purchased natural gas are placed in underground storage inventory during off-peak season to accommodate higher customer demand during the winter heating season.

Interstate Pipeline

The interstate pipeline operations of Equitable Utilities include the natural gas transmission, storage and gathering activities of Equitrans, L.P. (Equitrans) and Carnegie Interstate Pipeline Company (Carnegie Pipeline). The interstate pipeline division offers gas transportation, storage, gathering and related services to its affiliates and others in the Northeastern United States including, but not limited to, Dominion Resources, Inc.; Public Service Electric and Gas Company; Keyspan Corporation; NiSource, Inc.; PECO Energy and Amerada Hess Corporation. In 2003, approximately 67% of transportation volumes and approximately 78% of revenues are from affiliates.

In the second quarter 2002, Equitrans filed with the Federal Energy Regulatory Commission (FERC) to merge its assets and operations with the assets and operations of Carnegie Pipeline in order to create operating efficiencies. In July 2003, Equitrans received an order from the FERC approving the merger of Equitrans and Carnegie Pipeline. On January 1, 2004, the merger of Equitrans and Carnegie Pipeline was effectuated with Equitrans surviving the merger.

The present regulatory environment is designed to increase competition in the natural gas industry. This environment has created a number of opportunities for pipeline companies to expand services and serve new markets. The Company has taken advantage of selected market opportunities by concentrating on Equitrans underground storage facilities and the location of its pipeline system which allows interconnects with five major interstate pipelines Texas Eastern Transmission, Columbia Gas Transmission, National Fuel Gas Supply, Tennessee Gas Pipeline and Dominion Transmission. The storage facilities and pipeline system are located adjacent to natural gas markets in the Northeastern United States. These interconnecting pipelines provide ample opportunities for Equitrans to access natural gas markets in the Northeastern United States. The Company believes that servicing local distribution companies in the Northeast to meet their load demands for the winter months presents growth opportunities.

Energy Marketing

Equitable Utilities unregulated marketing operations, Equitable Energy, LLC (Equitable Energy), purchases, stores and sells natural gas at both the retail and wholesale level, primarily in the Appalachian and mid-Atlantic regions. Services and products offered by the marketing operations include commodity procurement and delivery, physical natural gas management operations and control, and customer support services to the Company s natural gas customers. Energy marketing manages Equitable Gas supply needs as permitted by the performance-based rate incentives described below.

The Company also engages in trading and risk management activities with the objective of limiting exposure to shifts in market prices and optimizing the use of assets described above. Equitable Energy uses prudent asset management to hedge projected production, to optimize storage capacity assets through trading activities and to perform outsourced risk management services for large industrial customers.

The Company continues to reduce its trading activities, which are limited to trading derivative commodity instruments. The Company s trading activity as of December 31, 2003 had a mark-to-market value of approximately $0.2 million. This amount is insignificant relative to the consolidated financial position, results of operations and cash flows of the Company.

Rates and Regulation

Equitable Utilities distribution rates, terms of service, contracts with affiliates and issuance of securities are subject to comprehensive regulation by the Pennsylvania Public Utility Commission (PA PUC). The distribution rates, terms of service and contracts with affiliates are also subject to comprehensive regulation by the Public Service Commission of West Virginia, and the distribution rates are subject to regulation by the Kentucky Public Service Commission. Pipeline safety is generally regulated by the rules of the Federal Department of Transportation and/or by the state regulatory commission. The Occupational Safety and Health Administration (OSHA) also imposes certain additional safety regulations on the operations of Equitable Utilities.

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and the sale for resale of natural gas, including transportation rates, storage tariffs and various other matters, are subject to federal regulation, primarily by the FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC s regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. Some of the trading activities of the energy marketing operations are subject to regulation by, among others, the Commodity Futures Trading Commission (CFTC), the FERC, and the PA PUC.

The pipeline operations of Equitrans and Carnegie Pipeline are subject to rate regulation by the FERC. In 1997, Equitrans filed a general rate change application (rate case). The rate case was resolved through a FERC approved settlement among all parties. The settlement provided, with certain limited exceptions, that Equitrans not file a general rate increase with an effective date before August 1, 2001 and must file a general rate case application to take effect no later than August 1, 2003. In the second quarter 2002, Equitrans filed with the FERC to merge its assets and operations with the assets and operations of Carnegie Pipeline. In April 2003, Equitrans filed a proposed settlement with the FERC related to the application to merge its assets with the assets of Carnegie Pipeline. The settlement also provided for a deferral to April 2005 of the August 1, 2003 rate case filing requirement. This proposed settlement was broadly supported by most parties. On July 1, 2003, Equitrans received an order from the FERC approving the merger of Equitrans and Carnegie Pipeline but denying the request for deferral of the requirement to file a rate case by August 1, 2003. In response to the July 1, 2003 order, Equitrans filed for and received an extension of time for its rate case filing deadline from August 1, 2003 until December 1, 2003. Also in response to the July 1, 2003 order, on January 1, 2004, the merger of Equitrans and Carnegie Pipeline was effectuated with Equitrans surviving the merger.

Equitrans timely filed its rate case application on December 1, 2003. On December 31, 2003, in accordance with the Natural Gas Act, the FERC issued an order accepting in part and rejecting in part Equitrans general rate application. Certain of Equitrans proposed tariff sheets have been accepted subject to a 5-month suspension period but Equitrans requests for revenue relief were denied. The increase was rejected in large part because Equitrans did not provide cost and revenue data for Carnegie Pipeline. Equitrans is planning to assemble cost and revenue data for Carnegie Pipeline and re-file its rate case application in the first quarter of 2004. Consistent with the Company s original December 1, 2003 filing, Equitrans upcoming rate case application will address several issues including establishing an appropriate return on the Company s capital investments, addressing the Company s pension funding levels, accruing for post-retirement benefits other than pensions and restructuring its storage services. The Company s request for rate relief is expected to be approximately $18.0 million. In conjunction with the Company s application for rate relief, Equitrans filed a rehearing request on January 30, 2004, seeking reconsideration of the FERC s December 31, 2003 order. Equitrans will continue to explore and evaluate settlement options throughout the pendency of the case.

For additional discussion of regulatory matters involving Equitable Utilities, see Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) and Note 11 to the Company s consolidated financial statements.

Competitive Environment

Over the last three years, Equitable Gas has been working with state regulators to shift the manner in which costs are recovered from traditional cost of service rate making to performance-based rate making. In 2001, Equitable Gas received approval from the PA PUC to implement a performance-based incentive that provides to customers a purchased gas cost credit which is fixed in amount, while enabling Equitable Gas to retain all revenues in excess of the credit through more effective management of upstream interstate pipeline capacity. During the third quarter 2002, the PA PUC approved a one-year extension of this program through September 2004. In that same order, the PA PUC approved a second performance-based initiative related to balancing services. This initiative runs through 2005. During the second quarter of 2003, Equitable Gas reached a settlement with all parties to extend its performance-based purchased gas cost credit incentive through September 2005. The settlement also included a new performance-based incentive, which allows Equitable to retain 25% of any revenue generated from a new service designed to increase the recovery of capacity costs from transportation customers. A PA PUC Order approving the settlement was issued in September 2003.

In the third quarter 2002, the PA PUC issued an order approving Equitable Gas   request for a Delinquency Reduction Opportunity Program. The program gives incentives to eligible customers to make payments exceeding their current bill amount and to receive additional credits from Equitable Gas to reduce the customer   s delinquent balance. The program will be fully funded through customer contributions and a surcharge in rates.

In the second quarter 2002, the PA PUC authorized Equitable Gas to offer a sales service that would give residential and small business customers the alternative to fix the unit cost of the commodity portion of their rate. The program was developed in response to customer requests for a method to reduce the fluctuation in gas costs. This first of its kind program in Pennsylvania is another in a series of service-enhancing initiatives implemented by Equitable Gas. A competitor, Dominion Retail, Inc., appealed the PA PUC order authorizing the new service to the Commonwealth Court of Pennsylvania. In September 2003, the Commonwealth Court of Pennsylvania issued an order affirming the PA PUC decision granting Equitable Gas authority to implement the new Fixed Sales Service. To date, Equitable Gas has not offered Fixed Sales Service but will continue to analyze the feasibility of a Fixed Sales Service in the future.

Equitrans will be experiencing significant competitive challenges, influenced by the ultimate resolution of the rate case, over the next few years as 22% of the pipeline s firm contracts expire in calendar year 2004 and another 73% expire in 2005. Despite these challenges, Equitrans believes that servicing local distribution companies in the Northeastern United States presents growth opportunities.

The large industrial market is extremely competitive resulting in very low realized margins. Despite the continued national economic downturn experienced during 2002, the industrial activity and volumes increased in 2002 compared to 2001. However, the activity and volumes decreased in 2003 compared to 2002 due to high gas prices. Fluctuations in industrial demand do not have a significant impact on the Company s financial results.

Equitable Supply

Prior to 2002, Equitable Supply was referred to as Equitable Production. In 2002, the Company changed the name of the segment to Equitable Supply because the segment consists of two activities: production and gathering. This change does not impact the year-to-year comparability of the business segment.

Equitable s production business develops, produces and sells natural gas and, to a limited extent, crude oil and its associated by-products, with operations in the Appalachian region of the United States. Its natural gas gathering business engages in gathering the Company s and third party gas and in the limited processing and sale of natural gas liquids. Equitable Supply generated approximately 54% of the Company s net operating revenues in 2003.

Production

Equitable s production business, operating through Equitable Production Company and several smaller affiliates (referred to collectively as Equitable Production), is the largest owner of proved natural gas reserves in the Appalachian Basin, the oldest and geographically one of the largest natural gas producing regions in the United States. Equitable Production currently operates approximately 12,000 producing wells in the Appalachian Basin. As of December 31, 2003, the Company estimated its total proved reserves to be 2,067 billion cubic feet equivalent (Bcfe), including proved undeveloped reserves of 484 Bcfe.

The Company s reserves are located entirely in the Appalachian Basin. The Appalachian Basin is characterized by wells with comparatively low rates of annual decline in production (wells generally produce for periods longer than 50 years), low production costs per well and high British thermal unit (Btu), or energy, content. For operational and commercial reasons, some of the gas produced is processed to allow heavier hydrocarbon (propane, butane and ethane) streams to be stripped and sold separately. Within certain limits, the Company can vary the amount of the hydrocarbons extracted. This can cause the conversion rate between energy content (measured in Btu) to volumes (measured in million cubic feet equivalent (MMcfe)) to vary. Once drilled and completed, wells in the Appalachian Basin typically have low ongoing operating and maintenance requirements and require minimal capital expenditures. These rates of production are low in comparison to other geographic locations in the United States. Many of the Company s wells in these areas have been producing for decades, and in some cases since the early 1900 s. Reserve estimates for properties with long production histories are generally more reliable than estimates for properties with shorter production histories.

Virtually all of the Company s wells are low risk development wells drilled to relatively shallow depths ranging from 1,000 to 7,000 feet below the surface. 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 mixed or commingled. Commingled production lowers producing costs on a per unit basis compared to isolated zone completions.

In the Appalachian Basin during 2003, Equitable Production drilled 401 gross wells at a success rate of 100%. This drilling was concentrated within the core areas of southwest Virginia, southern West Virginia and southeast Kentucky. This activity resulted in 27.8 million cubic feet (MMcf) per day of gas sales and proved developed reserve additions of 120 Bcfe. The 120 Bcfe of proved developed reserve additions include approximately 32 billion cubic feet (Bcf) of proved developed extensions, discoveries and other additions that were not previously classified as undeveloped. The remaining 88 Bcfe relate to proved undeveloped reserves that were transferred to proved developed reserves.

Equitable Production currently has an inventory of 3.6 million gross acres of which approximately 73% is considered undeveloped. As of December 31, 2003, the Company estimated the proved undeveloped reserves of the underlying leases and fee interests to be 484 Bcfe from approximately 1,616 proved undeveloped drilling locations. In the last three years, Equitable Production has completed substantially all of the wells it has drilled. Additionally, given the fact that the Company has developed proved undeveloped reserves of 88 Bcfe and 85 Bcfe during 2003 and 2002, respectively, and that the Company s plans include developing similar levels of proved undeveloped reserves going forward, the Company believes that the 484 Bcfe of proved undeveloped reserves will be developed in a reasonable period of time, currently estimated to be five years.

Gathering

Equitable Gathering is comprised of Kentucky West Virginia Gas Company, LLC, Equitable Field Services LLC, Equitable Gathering, LLC and the gathering operations of Equitable Production (referred to collectively as Equitable Gathering). Equitable Gathering derives its revenues from the largest gas gathering and production pipeline system in the Appalachian Basin. The system includes approximately 10,000 miles of pipeline located throughout West Virginia, eastern Kentucky, southwestern Virginia, eastern Ohio and portions of Pennsylvania. Over 80% of the volumes through the pipeline system interconnect with three major interstate pipelines: Columbia Gas Transmission, East Tennessee Natural Gas Company, and Dominion Transmission. The system also maintains interconnects with Equitrans, the Company s interstate transmission affiliate that affords access to the Pittsburgh market area for gathered gas. Maintaining these interconnects provides the Company with access to multiple markets and the flexibility to redirect deliveries when flow interruptions occur. Flow management through these connections also allows the Company to optimize operating conditions for these gathering assets.

Gathered sales volumes for 2003 totaled 126.7 Bcf, of which approximately 47% related to affiliate sales volumes (primarily the gathering of Equitable Production s equity sales volumes), 36% related to third party volumes, and the remainder related to volumes in which interests were sold by the Company but which the Company still operates for a fee. Approximately 69% of the Company s 2003 gathering revenues were from affiliates. The Company is currently charging below market rates to certain of its third party gathering customers and is continuing to make efforts to raise those rates to market.

In July 2001, Equitrans filed an application with the FERC to transfer all of its natural gas pipeline gathering systems located in West Virginia and Pennsylvania to Equitable Gathering. On February 14, 2002, the FERC approved the application resulting in the transfer of gathering systems. The transfer was effective January 1, 2002 for segment reporting purposes. The systems transferred consisted of approximately 1,200 miles of low pressure, small diameter pipeline, and related facilities used to gather gas from wells in the region. Total system throughput is approximately 13.1 Bcf annually, generating annual revenues of approximately $4.0 million. The effect of this transfer was not material to the results of operations or financial position of the Equitable Utilities or Equitable Supply segments. Therefore, segment results have not been restated for this transfer.

Prepaid Natural Gas Sales

In December 2000, the Company entered into two prepaid natural gas sales contracts for a total of approximately 52.7 MMcf of reserves. The Company is required to deliver certain fixed quantities of natural gas during the term of the contracts. The first contract was for five years with net proceeds of $104.0 million and has two years remaining. The second contract was for three years with net proceeds of $104.8 million and was completed at the end of 2003. These contracts were recorded as prepaid forward sales and are recognized in income as deliveries occur.

Acquisitions and Divestitures

In December 2001, the Company sold its oil-dominated fields in order to focus on natural gas activities. The sale resulted in a decrease of 63 Bcfe of proved developed producing reserves and 5 Bcfe of proved undeveloped reserves for proceeds of approximately $60 million. The field produced approximately 4 Bcfe annually. Although the Company no longer operates these properties, it continues to gather and market the natural gas produced for a fee. During 2003 and 2002, these fees were approximately $1.7 million and $1.5 million, respectively.

In February 2003, the Company sold approximately 500 of its low-producing wells, within two of its non-strategic districts, in two separate transactions. The sales resulted in a decrease of approximately 13 Bcf of net reserves for proceeds of approximately $6.6 million. The wells produced approximately 1.0 Bcf in 2002. The Company did not recognize a gain or a loss as a result of this disposition.

In February 2003, the Company purchased the remaining 31% limited partner interest in Appalachian Basin Partners, LP (ABP) from the minority interest holders for $44.2 million. The ABP partnership was formed in November 1995 when the Company monetized Appalachian gas properties qualifying for the nonconventional fuels tax credit. The Company retained a partnership interest in the gas properties that increased substantially based on the attainment of a performance target, which was met near the end of 2001. The Company consequently consolidated the partnership starting in 2002, and the remaining portion not owned by the Company was recorded as minority interest. The 31% limited partner interest purchased by the Company represents approximately 60.2 Bcf of reserves.

Competitive Environment

Equitable Supply s commercial operations are focused on selling a commodity at a high level of reliability of delivery. Equitable Supply does not actively engage in any activities to differentiate its products in an extremely competitive market and therefore receives market based pricing. Equitable Supply s commercial operations are located in the Appalachian Basin. Because the Appalachian Basin is geographically located in the Northeastern United States, gas prices are generally higher than those prices for gas located in the Gulf region of the country given the differences in supply and demand of natural gas in those areas. This location provides Equitable Supply a price advantage over those companies located in the Gulf region of the country.

The Company has noticed some relative value erosion of Mid-Atlantic basis in recent months as a result of new base load gas supplies. If the rate of supply growth exceeds the Mid-Atlantic region s growth in demand, there may be further weakening in basis, especially in the summer months. At this time, this erosion has not had a significant impact on the Company s results.

The combination of its long-lived production, low drilling costs, high drilling completion rates at shallow depths and proximity to natural gas markets has had a substantial impact on the development of the Appalachian Basin, resulting in a highly fragmented operating environment. In 2003, Kentucky, Virginia and West Virginia had approximately 4,500 independent operators and approximately 100,000 producing natural gas and oil wells. Also, the historical availability of tax incentives has resulted in extensive drilling in the shallow formations with these low technical risk characteristics.

Hedging Activities

Equitable has historically entered into hedging contracts with respect to forecasted natural gas production and third party purchases and sales at specified prices for a specified period of time. The Company s hedging strategy and information regarding derivative instruments used are outlined in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and in Note 3 to the consolidated financial statements.

NORESCO

NORESCO provides an integrated group of energy-related products and services that are designed to reduce its customers operating costs and improve their energy efficiency. The segment s activities are comprised of performance contracting, energy efficiency programs, combined heat and power and central boiler/chiller plant development, design, construction, ownership and operation. NORESCO s customers include governmental, military, institutional, commercial and industrial end-users. In 2003, approximately 41% of NORESCO s operating revenues were from the federal government. NORESCO also develops, constructs and operates facilities in the United States and operates private power plants in selected international countries. NORESCO provided approximately 6% of the Company s net operating revenues in 2003.

The segment s performance contracting group provides a turnkey solution for clients to implement energy efficiency and conservation projects. Guaranteed energy savings are used to pay for installation of new energy-efficient equipment and systems. Within the performance contracting solution, NORESCO provides engineering analysis, project management, construction, financing, operations and maintenance, and energy savings measurement and verification. This is a growing market, primarily in the public sector. Typically, at any given time, NORESCO has a range of 60 to 100 on-going construction contracts, depending on the size and mix of the projects, and approximately 150 to 250 on-going operations and maintenance projects.

The segment s energy infrastructure group provides clients with development, construction and operation and maintenance services for cogeneration, central plant, and private power generation facilities in the United States. NORESCO also operates private power plants in selected international countries. These projects serve a diverse clientele including governmental, institutional, commercial and industrial customers and utilities. NORESCO s capabilities offer a turnkey approach to energy infrastructure programs including project development, equipment selection, fuel procurement, environmental permitting, construction, financing and operations and maintenance. Some of these projects are held through equity in nonconsolidated investments.

Revenue backlog increased to $134.2 million at year-end 2003 from $118.2 million at the end of 2002. A substantial portion of the backlog is expected to be constructed within the next eighteen months.

Competitive Environment

NORESCO operates in a highly competitive market segment, with a significant number of competitors, including affiliates of large energy companies that have entered this market in recent years. NORESCO s focus is on larger contracts in core performance contracting and energy infrastructure markets.

Many energy infrastructure and performance contracting projects require that NORESCO provide a surety bond in advance of being awarded a contract. NORESCO s continued ability to obtain adequate bonding could affect NORESCO s business.

On September 30, 2003, the enabling legislation for the performance contracting work that NORESCO performs for the federal government under the Department of Energy contracts lapsed and is pending extension in Congress. Until this issue is resolved, the NORESCO segment s ability to sign new contracts under the Department of Energy master agreements is affected. However, the Department of Defense has informed

NORESCO that it is not interpreting the statutory lapse as prohibiting new awards under existing master agreements.

Foreign Operations

The NORESCO segment has investments in nonconsolidated partnerships located in foreign countries, specifically in Jamaica, Panama and Costa Rica. These investments represent equity ownership interests in independent power plant projects. The projects were constructed and two currently operate as the result of specific needs of private or governmental entities to secure power that is more cost effective and reliable than existing sources of power. These projects consist of energy production plants that have been financed using nonrecourse financing at the project level. Typically, long-term power purchase agreements are signed with the customer in the host country, whereby the customer agrees to purchase the energy generated by the plant. Once initial contracts expire, the projects attempt to secure new power capacity contracts. The economic environment and market price for power in these countries directly impacts new power capacity contracts and any power sold on the open market. These market prices have adversely impacted our equity earnings in these projects.

The NORESCO projects are held through equity in nonconsolidated entities. All earnings in these projects are reported through the Statement of Consolidated Income as equity in earnings of nonconsolidated investments. See further information at Note 9 to the consolidated financial statements. NORESCO has not made any international investments since April 2001 and does not expect to make any international investments in 2004. NORESCO has a total cumulative investment in these two projects of $27.3 million as of December 31, 2003 and NORESCO s ownership share of the earnings for 2003, 2002 and 2001 related to the total investments was $2.5 million, $4.7 million and $7.6 million, respectively. The Company is currently investigating all possible alternatives related to these international projects.

The Company reviewed its equity investment related to Petroelectrica de Panama LDC, an independent power plant project in Panama, during the fourth quarter of 2003 as the project was unsuccessful in securing power capacity contracts. Moreover, the market prices for power supply in Panama make it uneconomical to operate the plant. As a result, the plant was shut down during January 2004. The Company is evaluating various options including the closing of the plant, both temporarily and permanently, and the sale of the plant. As part of the impairment analysis, the Company performed a probability cash flow analysis using the undiscounted future cash flows and compared this amount to the book value of the equity investment. The probability cash flows resulted in a lower fair value than the carrying value, and an impairment was deemed necessary. An impairment of $11.1 million was recorded in 2003 and represents the full value of NORESCO s equity investment in the project. Further, NORESCO also had an investment in a power plant in Jamaica, which was impaired in 2002 and deconsolidated in 2003.

Westport Resources Corporation

On April 10, 2000, the Company merged its Gulf of Mexico operations with Westport Oil and Gas Company for debt repayment of approximately $50 million in cash and approximately 49% of a minority interest in the combined company, named Westport Resources Corporation (Westport). The Company accounted for this investment under the equity method of accounting. In October 2000, Westport completed an initial public offering (IPO) of its shares. The Company sold 1.325 million shares in this IPO. On August 21, 2001, Westport Resources completed a merger with Belco Oil & Gas.

On March 31, 2003, the Company donated 905,000 shares of Westport to a community giving foundation. In November 2003, the Company sold approximately 1.3 million shares of Westport, with a book value of $16.53 per share, at $25.55 per share. In December 2003, the Company sold an additional 220,000 shares of Westport at $28.51 per share. After these transactions, the Company currently owns approximately 11.53 million shares, or 17.1% of Westport, a decrease from 20.8% at the end of 2002. The tax basis of the investment was $61.2 million as of December 31, 2003. The Company does not have operational control of Westport. As a result of the decreased ownership, the Company changed the accounting treatment for its investment from the equity method to available-for-sale, effective March 31, 2003. The change in accounting method eliminated the inclusion of Westport s results in the Company s earnings subsequent to March 31, 2003. The Company s investment in Westport was reclassified to Investments, available-for-sale on the Company s consolidated financial statements, and was adjusted to fair market value, in accordance with Statement of Financial Accounting Standards (SFAS) No. 115 Accounting for Certain Investments in Debt and Equity Securities.

For additional discussion of Westport, see Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 1 to the Company s consolidated financial statements.

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Composition of Segment Operating Revenues

Presented below are operating revenues as a percentage of total operating revenues for each class of products and services greater than 10% of each of the three business segments during the years 2001 through 2003. In 2003, intercompany segment eliminations are recorded against marketed natural gas sales. Prior year percentages have been reclassified for comparative purposes.

	2003	2002	2001
Equitable Utilities:			
Residential natural gas sales	27%	21%	25%
Marketed natural gas	15	22	24
Equitable Supply:			
Produced natural gas equivalents	24	20	20
NORESCO:			
Energy service contracting	16	18	14

Financial Information About Segments

See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 2 to the consolidated financial statements for financial information by business segment.

Financial Information About Geographic Areas

All but an insignificant amount of the Company s assets or operations are located in the continental United States.

Environmental

In July 2002, the United States Environmental Protection Agency (EPA) published a final rule that amends the Oil Pollution Prevention Regulation. The effective date of the rule was August 16, 2002. Under the final rule, Owners/Operators of existing facilities were to revise their Spill Prevention, Control and Countermeasure (SPCC) plans on or before February 17, 2003 and were required to implement the amended plans as soon as possible but not later than August 18, 2003. On April 17, 2003, the EPA extended the deadline to adopt a plan amendment to August 17, 2004 and the deadline to comply with the amended plan to February 18, 2005. There is currently active litigation regarding the final rule and management anticipates that the regulation will be modified. Nonetheless the Company is studying, and is preparing to implement, its plan of compliance. The ultimate outcome of the pending litigation and any regulatory modification may affect the Company s ability to timely comply and will affect the total costs of compliance, currently expected to be $18.0 million, approximately two-thirds of which are expected to be capitalized but were not approved as part of the 2004 capital budget.

In addition to the SPCC requirements, the Company is subject to other 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 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.

Any estimated costs associated with identified situations that require remedial action are accrued with certain costs deferred as regulatory assets, as applicable. The Company has identified situations that require remedial action for which approximately $4.4 million is included in other long-term liabilities in the consolidated financial statements at December 31, 2003.

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 have adequate capacity, are well maintained and, where necessary, are replaced or expanded to meet operating requirements.

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 and transmission facilities in Pennsylvania and West Virginia.

The interstate pipeline operations consist of approximately 1,500 miles of transmission, storage 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 500 MMcf per day of peak delivery capability and 59 Bcf of storage capacity of which 27 Bcf is working gas. These storage reservoirs are clustered, with eight in northern West Virginia and seven in southwestern Pennsylvania. Equitrans has conducted a geologic assessment and volumetric analysis of its storage reservoirs, in an effort to enhance its storage capacity and deliverability capability. The analyses, which were completed in late-2003, indicate the need to replenish certain base gas volumes. The replenishment of these volumes will be addressed in the Company s upcoming rate case application which will be filed with the FERC in the first quarter 2004.

Equitable Utilities primary office space is located in leased office space in Pittsburgh, Pennsylvania. This segment leases other office space and equipment in Pennsylvania that is not significant to the operations of the segment.

Equitable Supply. This business segment owns or controls all of the Company s acreage of proved developed and undeveloped natural gas and oil production properties. The segment also owns and operates approximately 10,000 miles of gathering pipelines and 182 compressor units comprising 124 compressor stations with over 90,000 hp of installed capacity, as well as other general property and equipment. This segment s production and gathering properties are located in the Appalachian Basin, specifically Kentucky, Ohio, Pennsylvania, Virginia, and West Virginia. Information relating to Company estimates of natural gas and crude oil reserves and future net cash flows is provided in Note 26 (unaudited) to the consolidated financial statements.

Natural Gas and Crude Oil Production:

	2003	2002	2001
Natural Gas:			
MMcf produced	69,422	67,171	64,706

Average well-head sales price per Mcfe sold (net of hedges)	$ 3.91	$ 3.47	$ 3.75
MMcfe operated (a)	92,538	91,793	93,167
MMcfe gathered (b)	126,674	123,581	106,832
Crude Oil:			
Thousands of barrels produced	83	127	451
Average sales price per barrel	$ 26.08	$ 20.78	$ 17.82

(a) Includes produced volumes and volumes from properties the Company operates for third parties for a fee.

(b) Includes operated volumes as well as volumes gathered as a service performed for third parties for a fee.

Average production cost, including severance taxes (lifting cost), of natural gas and crude oil during 2003, 2002, and 2001 was $0.499, $0.387, and $0.482 per Mcf equivalent, respectively.

	Natural Gas	Oil
Total productive wells at December 31, 2003:		
Total gross productive wells	12,377	21
Total net productive wells	7,774	15
Total acreage at December 31, 2003:		
Total gross productive acres	965,880	
Total net productive acres	907,927	
Total gross undeveloped acres	2,618,789	
Total net undeveloped acres	2,452,913	

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

	2003	2002	2001
Exploratory wells:			
Productive			
Dry			
Development wells:			
Productive	354.8	338.4	293.5
Dry		1.0	

No report has been filed with any federal authority or agency reflecting a 5% or more difference from the Company s estimated total reserves.

Substantially all 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 Pittsburgh, Pennsylvania and Charleston, West Virginia. The segment also leases compressors in Pennsylvania, West Virginia, Virginia and Kentucky. This segment leases other office space and equipment in Pennsylvania, West Virginia, Virginia and Kentucky that is not significant to the operations of the segment.

NORESCO. NORESCO is based in Westborough, Massachusetts, and leases offices in 18 locations throughout the United States. The following table provides a summary of the number of leased offices by state:

State	Number of Offices
California	5
Colorado	1
Connecticut	1
Florida	1
Hawaii	1
Massachusetts	2
New Hampshire	1
New York	2
Pennsylvania	1
Texas	1
Virginia	1
Washington	1

Headquarters. The headquarters is located in leased office space in Pittsburgh, Pennsylvania. The Company signed a long-term lease to consolidate all of its administrative operations with Continental Real Estate Companies, which will own and construct the building at the North Shore in Pittsburgh. Plans call for the building to be complete in late 2004 or early 2005.

Item 3. Legal Proceedings

On October 15, 2003, Jamaica Broilers Group Limited (JBG) and Energy Associates Limited (EAL) filed a multi-count complaint against Equitable and certain of its affiliates in U.S. District Court (Western District of PA). The suit alleges, among other things, that Equitable and certain of its affiliates improperly interfered with and/or made misrepresentations with respect to certain contractual relations involving EAL/ERI Cogeneration Partners L.P. (EAL/ERI), an affiliate of Equitable that operates an energy infrastructure project in Jamaica. In addition, the Western District lawsuit alleges that certain of Equitable s affiliates breached and/or were negligent in performing their duties under certain related infrastructure contracts, and that JBG and EAL incurred actual damages in excess of $8.0 million. ERI JAM, LLC, the subsidiary that holds the Company s interests in EAL/ERI filed for bankruptcy protection under Chapter 11 in U.S. Bankruptcy Court (Delaware) in April 2003. In the third quarter 2003, ERI JAM, LLC transferred operational control of the international infrastructure project under the partnership agreement to the other general partner. EAL is a limited partner in EAL/ERI, and JBG is an affiliate of EAL. JBG and EAL have also filed a claim against ERI JAM, LLC as Debtor-in-Possession in the Chapter 11 case. Equitable and its affiliates intend to vigorously defend the Western District litigation, which they view as without merit. Resolution in the litigation and Chapter 11 proceedings pursuant to a global settlement is being sought.

In addition, there are various other claims and legal proceedings against the Company arising in the normal course of business. Although counsel is unable to predict with certainty the ultimate outcome, management and counsel believe that the Company has significant and meritorious defenses to any claims and intends to pursue them vigorously. The Company has provided adequate reserves and therefore believes that the ultimate outcome of any such matter currently pending against the Company will not materially affect the financial position or results of operations of the Company. The reserves recorded by the Company do not include any amounts for legal costs expected to be incurred. It is the Company s policy to recognize any legal costs associated with any claims and legal proceedings against the Company as they are incurred.

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, 2003.

Executive Officers of the Registrant (as of March 1, 2004)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
John A. Bergonzi (51)	Vice President and Corporate Controller (January 2003)	Elected to present position January 2003; Corporate Controller and Assistant Treasurer from December 1995 to December 2002.
Philip P. Conti (44)	Vice President, Finance and Treasurer (August 2000)	Elected to present position August 2000; Director of Planning and Development from June 1998 to August 2000.
Randall L. Crawford (41)	Vice President (January 2003)	Elected to present position January 2003; President, Equitable Gas Company from January 2003 to present; Executive Vice President, Equitable Gas Company from November 2000 to December 2002; Senior Vice President, Equitable Gas Company from December 1999 to November 2000; Vice President, Equitable Gas Company from April 1998 to December 1999.
Murry S. Gerber (51)	Chairman, President and Chief Executive Officer (June 1998)	Elected to present position May 2000; acting President, Equitable Production Company from January 1, 2004 to present; President and Chief Executive Officer from June 1, 1998 to present.
Joseph E. O Brien (51)	Vice President (January 2001)	Elected to present position January 2001; President, NORESCO, LLC from January 2000 to present; Senior Vice President, Construction & Engineering from June 1993 to January 2000.
Johanna G. O Loughlin (57)	Senior Vice President, General Counsel and Secretary (December 1996)	Elected to present position January 2002; Vice President, General Counsel and Secretary from May 1999 to January 2002; Vice President and General Counsel from December 1996 to May 1999.

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Charlene Petrelli (42)	Vice President, Human Resources (January 2003)	Elected to present position January 2003; Director of Corporate Human Resources from October 2000 to December 2002; Director of Human Resources, Fisher Scientific International, Inc. (a provider of equipment, supplies, and services for the clinical laboratory and scientific research markets) from December 1999 to September 2000; Senior Manager Human Resources, Merck & Co, Inc. (a research-driven pharmaceutical products and services company) from March 1998 to December 1999.
David L. Porges (46)	Executive Vice President and Chief Financial Officer (July 1998)	Elected to present position February 2000; Senior Vice President and Chief Financial Officer from July 1998 to January 2000.

Messrs. Gerber and Porges have executed employment agreements with the Company. All other executive officers serve at the pleasure of the board. 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 and Related Stockholder Matters

The Company s common stock is listed on the New York Stock Exchange and the Philadelphia 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):

	2003			2002		
	High	Low	Dividend	High	Low	Dividend
1st Quarter	$ 37.90	$ 34.44	$ 0.170	$ 35.67	$ 29.32	$ 0.160
2nd Quarter	42.00	37.08	0.200	37.55	33.54	0.170
3rd Quarter	41.65	37.85	0.300	36.49	28.67	0.170
4th Quarter	43.42	39.95	0.300	36.89	32.09	0.170

As of February 13, 2004, there were approximately 4,453 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. The Company is targeting dividend growth at a rate similar to the rate of earnings per share growth. Based on currently foreseeable market conditions, the Company anticipates dividends will continue to be paid on a regular quarterly basis.

Item 6. **Selected Financial Data**

	2003	2002	2001	2000	1999
			(Thousands except per share amounts)		
Operating revenues (a)	$ 1,047,277	$ 1,069,068	$ 1,109,334	$ 1,036,531	$ 844,625
Income from continuing operations before cumulative effect of accounting change (b)	$ 173,557	$ 150,626	$ 151,808	$ 106,173	$ 69,130
Income from continuing operations before cumulative effect of accounting change per share of common stock:					
Basic	$ 2.80	$ 2.40	$ 2.36	$ 1.63	$ 1.02
Diluted	$ 2.74	$ 2.36	$ 2.30	$ 1.60	$ 1.01
Total assets	$ 2,939,892	$ 2,436,891	$ 2,518,747	$ 2,424,914	$ 1,789,574
Long-term debt	$ 653,414	$ 471,250	$ 271,250	$ 287,789	$ 298,350
Preferred trust securities	$	$ 125,000	$ 125,000	$ 125,000	$ 125,000
Cash dividends declared per share of common stock	$ 0.97	$ 0.67	$ 0.63	$ 0.59	$ 0.59

(a) Operating revenues for years prior to 2002 have been reclassified to reflect all gains and losses associated with the Company s energy trading activities on a net basis as required by the Financial Accounting Standards Board s (FASB) Emerging Issues Task Force (EITF) in EITF No. 02-3, Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10 and No. 00-17.

(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 Accounting for Asset Retirement Obligations. The year ended December 31, 2002 excludes the negative cumulative effect of accounting change of $5.5 million related to the impairment of goodwill and income from discontinued operations of $9.0 million related to the sale of the Company s natural gas midstream operations.

See 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.

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

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 financial statements and results of operations are based upon Equitable s consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. 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 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.

Asset Impairment: The Company is required to test for asset impairment whenever events or changes in circumstances indicate that the carrying value of an asset might not be recoverable. The Company applies SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (Statement No. 144), in order to determine whether or not an asset is impaired. This Statement indicates that if the sum of the future expected cash flows associated with an asset, undiscounted and without interest charges, is less than the carrying value, an asset impairment must be recognized in the financial statements. The amount of the impairment is the difference between the fair value of the asset and the carrying value of the asset.

The Company believes that the accounting estimate related to an asset impairment is a critical accounting estimate as it is highly susceptible to change from period to period, because it requires management to make assumptions about cash flows over future years. These assumptions impact the amount of an impairment, which would have an impact on the income statement. Management s assumptions about future cash flows require significant judgment because actual operating levels have fluctuated in the past and are expected to do so in the future.

The Company reviewed its assets relating to a Jamaican power plant project during the second quarter of 2002, as the project had not been operating at expected levels and repeated remediation efforts were unsuccessful. Additionally, the future projections demonstrated that the losses associated with the assets were likely to continue. The Company determined, through its analysis, that an impairment existed. As part of the impairment analysis, the Company performed a probability cash flow analysis using the undiscounted future cash flows and compared this amount to the carrying value of the asset. The probability cash flows resulted in a lower fair value than the carrying value, and an impairment was deemed necessary. An impairment of $5.3 million was recorded in 2002.

Additionally, the Company holds several investments in nonconsolidated entities that are accounted for under the equity method. Accounting Principles Board No. 18, The Equity Method of Accounting for Investments in Common Stock (APB No. 18), requires a company to recognize a loss in the value of an equity method investment which 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. This is a critical accounting estimate for similar reasons as those above regarding assumptions about future cash flows.

The Company reviewed its equity investment related to Petroelectrica de Panama LDC, an independent power plant project in Panama, during the fourth quarter of 2003 as the project was unsuccessful in securing power capacity contracts. Moreover, the market prices for power supply in Panama make it uneconomical to operate the plant. As a result, the plant was shut down during January 2004. The Company is evaluating various options including the closing of the plant, both temporarily and permanently, and the sale of the plant. As part of the impairment analysis, the Company performed a probability cash flow analysis using the undiscounted future cash flows and compared this amount to the book value of the equity investment. The probability cash flows resulted in a lower fair value than the carrying value, and an impairment was deemed necessary. An impairment of $11.1 million was recorded in 2003 and represents the full value of NORESCO s equity investment in the project.

The Company also reviewed its equity investment in IGC/ERI Pan-Am Thermal Generating Limited (IGC/ERI), another independent power plant project in Panama, during the fourth quarter of 2003. Based on the analysis performed, the investment was not deemed to be impaired. IGC/ERI will compete to sign new long-term power purchase agreements with customers in the second and third quarters of 2004. The outcome of these contracts will affect the future cash flows of IGC/ERI and could impact a future impairment analysis. The Company will reassess the impairment analysis in late 2004 should the outcome be significantly different than currently anticipated. The book value of the Company s investment in IGC/ERI is $21.7 million at December 31, 2003.

Goodwill: Beginning in fiscal year 2002, goodwill was required to be evaluated annually for impairment, in accordance with SFAS No. 142, Goodwill and Other Intangible Assets (Statement No. 142). This Statement requires a two-step process be performed to analyze whether or not goodwill has been impaired. Step one is to test for potential impairment, which requires that the fair value of the reporting unit be compared to its book value. If the fair value is higher than the book value, no impairment occurs. If the fair value is lower than the book value, step two must be performed. Step two requires measurement of the amount of impairment loss, if any, and requires that a hypothetical purchase price allocation be done to determine the implied fair value of goodwill. The resulting fair value is then compared to the carrying value of goodwill. If the implied fair value of the goodwill is lower than the carrying value of the goodwill, an impairment must be recorded.

The Company believes that the accounting estimate related to the goodwill impairment is a critical accounting estimate because the underlying assumptions used for the discounted cash flow can change from period to period and these changes could cause a material impact to the income statement. Management s assumptions about discount rates, inflation rates and other internal and external economic conditions, such as expected growth rate, require significant judgment based on fluctuating rates and anticipated future revenues. Additionally, Statement No. 142 requires that the goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

As discussed in Note 12 to the consolidated financial statements, goodwill recorded was analyzed for impairment with the implementation of Statement No. 142. In 2002, the fair value of the Company s goodwill (all of which relates to NORESCO) was estimated using discounted cash flow methodologies and market comparable information. Based on the analysis, the implied fair value of the goodwill was less than the book value recorded for the goodwill. Therefore, the Company recognized an impairment. During the first quarter of 2002, the implied fair value of the goodwill, using the discounted cash flows methodology, was $51.7 million. The carrying value of the goodwill was $57.2 million, resulting in an after tax impairment charge of $5.5 million In the fourth quarters of 2003 and 2002, the Company performed the required annual impairment test of the carrying amount of goodwill and no further impairment was required.

Asset Retirement Obligations: The Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations (Statement No. 143), during fiscal year 2003 and its primary impact was to change the method of accruing for well plugging and abandonment costs. Statement 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 will increase 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 (DD&A), and the initial capitalized costs are depleted over the useful lives of the related assets.

The Company believes that the accounting estimate related to an asset retirement obligation is a critical accounting estimate because the underlying assumptions used for the value of the retirement obligation and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs and the assumed credit-adjusted risk free interest rate. Additionally, the estimated depletion rates of the related assets determine the period over which the capitalized costs are charged to expense.

As discussed in Note 1 to the consolidated financial statements, the Company recorded an after-tax charge to earnings of $3.6 million as a cumulative effect of accounting change in 2003 upon the adoption of Statement No. 143 and an asset retirement obligation at adoption of $28.7 million.

Allowance for Doubtful Accounts: The Company s Utility division, Equitable Gas, encounters risks associated with the collection of its accounts receivable. As such, 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. For 2003, the monthly provision was established at 4% of residential sales. Periodically, the reserve is reviewed for reasonableness. The historical rate 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.

The Company believes that the accounting estimate related to the allowance for doubtful accounts is a critical accounting estimate because the underlying assumptions used for the allowance can change from period to period and 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 expected operating income. Additionally, management reviews the adequacy of the allowance on a quarterly basis using the assumptions that apply at that time.

Due to the increase in gas commodity rates in 2003, and the colder than prior year weather, customer bills increased from 2002. As a result of this increase, Equitable Gas increased its allowance for doubtful accounts for the first quarter 2003. The provision recorded amounted to approximately 5% of residential revenues for 2003.

Performance Plan: The Company accounts for stock-based compensation awards under Accounting Principles Board Opinion No. 25 (APB No. 25). The Company treats its performance plans under which grants were awarded in 2003 and 2002, as variable plans.

The actual cost to be recorded for the plans will not be known until the measurement date, which is in December 2005 for the 2003 Plan and December 2004 for the 2002 Plan, requiring the Company to estimate the total expense to be recognized. The number of shares to be awarded in each plan is dependent upon attainment of certain relative total shareholder return performance goals relative to the performance of a peer group. In the current period, the Company estimated that the performance measures would be met at 130% of the full value of the shares for the 2003 Plan and for 200% of the full value of the shares for the 2002 Plan.

The Company believes that the accounting estimate related to the performance plan is a critical accounting estimate because it is likely to change from period to period based on the market price of the shares, the performance of the peer group and the level of performance by the employees involved. Additionally, the impact on the Statement of Consolidated Income of these changes could be material. Management s assumptions about future stock price and the amount of stock to ultimately be awarded requires significant judgment due to the volatility of the stock market.

Pension Plans: The calculation of the Company s net periodic benefit cost (pension expense) and benefit obligation (pension liability) associated with its defined benefit pension plan (pension plan) requires the use of a number of assumptions that the Company deems to be critical accounting estimates. Changes in these assumptions can result in different pension expense and liability amounts, and actual experience can differ from these assumptions. The Company believes that the two most critical assumptions are the expected long-term rate of return on plan assets and the discount rate.

The expected long-term rate of return reflects the average rate of earnings expected on funds invested or to be invested in the pension plan to provide for the benefits included in the pension liability. The Company establishes the expected long-term rate of return at the beginning of each fiscal year based upon information available to the Company at that time, including the pension plan s investment mix and the historical and forecasted rates of return on these types of securities. The pension plan s investment mix as of January 1, 2003 and 2004 approximated 60%

equity securities and 40% fixed income securities. 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 in accordance with SFAS No. 87, Employers Accounting for Pensions (Statement No. 87). Although the long-term rate is intended to be fairly consistent, the Company has reevaluated and reduced the rate in both 2003 and 2004. The expected long-term rates of return determined by the Company as of January 1, 2003 and 2004 totaled 8.75% and 8.25%, respectively. Pension expense increases as the expected long-term rate of return decreases. Therefore, had the Company assumed an expected long-term rate of return of 8.25% as of January 1, 2003, the Company s pension expense for 2003, excluding the effect of any settlements paid during this period, would have been approximately $0.5 million higher than the amount recorded.

The assumed discount rate reflects the current rate at which the pension benefits could effectively be settled. In estimating that rate, Statement No. 87 requires and the Company looks to rates of return on high quality, fixed income investments. The Company discounted its future pension liabilities using rates of 6.25% and 7.00% as of December 31, 2003 and 2002, respectively. The Company s pension liability increases as the discount rate is reduced. Lowering the discount rate by 0.5% (from 6.25% to 5.75%) would increase the Company s projected benefit obligation as of December 31, 2003 by approximately $5.0 million. Additionally, had the Company s discount rate decreased to 5.75% as of December 31, 2003, the Company s net periodic pension expense for 2004 would be projected to increase by approximately $0.2 million, as a significant portion of the pension plan s participants are retirees.

Variable Interest Entities: On July 1, 2003, the Company adopted FASB Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN No. 46). FIN No. 46 requires certain variable interest entities to be consolidated by the primary beneficiary of a variable interest entity, if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The determination of whether an entity is the primary beneficiary requires an analysis of expected losses and expected residual returns by the variable interest entity. This analysis must be made upon adoption and when certain triggering events occur.

The Company believes that the accounting estimates related to the calculations of expected losses and expected residual returns are critical accounting estimates because they require assumptions about cash flows over future years. Management s assumptions about discount rates, growth rates and other internal and external economic conditions require significant judgment based on fluctuating rates and anticipated future results. These assumptions impact whether the variable interest entity is consolidated, which would have an impact on the financial statements.

The adoption of FIN No. 46 required the consolidation of Plymouth Cogeneration Limited Partnership (Plymouth), a joint venture entered into by NORESCO, and the deconsolidation of EAL/ERI Cogeneration Partners LP (Jamaica), which is the partnership that holds the Jamaican power plant.

The consolidation of Plymouth removed the equity investment in Plymouth of $0.1 million and increases minority interest by $0.7 million in the Consolidated Balance Sheet. As of December 31, 2003, the Company consolidated $4.7 million in assets and $4.1 million in total liabilities, including nonrecourse long-term debt of $4.0 million of which $0.2 million was current.

Upon adoption of FIN No. 46, it was determined that Jamaica was a variable interest entity and that the Company was not the primary beneficiary. As a result, the Company deconsolidated Jamaica effective July 1, 2003. The deconsolidation of Jamaica removed $17.8 million of assets and $18.0 million of total liabilities in the Consolidated Balance Sheet, including nonrecourse project financing of $15.9 million, all of which was current. The Company did not establish an equity method investment in Jamaica upon deconsolidation, as the amount of such investment would be less than zero and there is no recourse against the Company beyond its investment in Jamaica.

Consolidated Results of Operations

Equitable s consolidated income from continuing operations before cumulative effect of accounting change for 2003 was $173.6 million, or $2.74 per diluted share, compared with $150.6 million, or $2.36 per diluted share, for 2002, and $151.8 million, or $2.30 per diluted share, for 2001.

The 2003 income from continuing operations before cumulative effect of accounting change increased 15% from 2002 due to an increase in average natural gas prices, gains on the sale of Westport stock, increased equity earnings in Westport prior to the Company s change in accounting treatment for its investment in Westport, an increase in sales volumes from production, less minority interest expense recognized in 2003 associated with the Company s ownership in ABP, and an impairment of the Company s Jamaica power plant recognized in 2002. The improved 2003 earnings were partially offset by an impairment of an equity investment in an independent power plant project located in Panama, costs associated with the 2003 Executive Performance Incentive Program, higher depreciation, depletion and amortization expense resulting from an increase in production volumes and the unit depletion rate, an increase in production and leasehold expenses primarily the result of an increase in severance taxes attributable to higher average natural gas prices and an increase in maintenance and other repairs, an increase in interest expense primarily due to a net increase in the amount of outstanding debt, an increase in benefit and insurance costs and the establishment of a community giving foundation.

The 2002 income from continuing operations before cumulative effect of accounting change decreased 1% from 2001 due to the decreased equity earnings in nonconsolidated investments primarily related to the dilution of the Company s ownership percentage in Westport as a result of stock offerings and mergers and acquisitions completed by Westport during the year, lower realized selling prices, increased benefit costs, and an impairment on the Jamaica power plant project. These factors were mostly offset by reduced expenses from 2001 initiatives and process improvements, lower income tax expense, increased drilling, production enhancements, cooler weather and increased commercial and industrial sales.

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, excluding Westport, and minority interest. Interest charges and income taxes are managed on a consolidated basis. Headquarter 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 and administrative costs totaling $20.4 million, $5.4 million and $8.0 million in 2003, 2002 and 2001, respectively, were not allocated to business segments. The increase in 2003 is primarily related to the 2003 Executive Performance Incentive Program more fully described in Note 20 to the consolidated financial statements.

Equitable Utilities

Equitable Utilities operations comprise the sale and transportation of natural gas to customers at state-regulated rates, interstate pipeline transportation and storage of natural gas subject to federal regulation, the unregulated marketing of natural gas, and limited trading activities.

Natural Gas Distribution

The local distribution operation of Equitable Gas provides natural gas services in southwestern Pennsylvania and to municipalities and other customers in northern West Virginia. In addition, Equitable Gas provides field line sales (also referred to as farm tap service as the customer is served directly from a well or gathering pipeline) in eastern Kentucky. Equitable Gas is subject to rate regulation by state regulatory commissions in Pennsylvania, West Virginia and Kentucky.

Over the last three years, Equitable Gas has been working with state regulators to shift the manner in which costs are recovered from traditional cost of service rate making to performance-based rate making. Performance-based rate making allows the customer and the Company to share in the benefit derived from increased efficiency. In 2001, Equitable Gas received approval from the PA PUC to implement a performance-based incentive that provides customers a purchased gas cost credit which is fixed in amount, while enabling Equitable Gas to retain all revenues in excess of the credit through more effective management of upstream interstate pipeline capacity. During the third quarter 2002, the PA PUC approved a one-year extension of this program through September 2004. In that same order, the PA PUC approved a second performance-based initiative related to balancing services. This initiative runs through 2005. During the second quarter of 2003, Equitable Gas reached a settlement with all parties to extend its performance-based purchased gas cost credit incentive through September 2005. The settlement also included a new performance-based incentive, which allows Equitable to retain 25% of any revenue generated from a new service designed to increase the recovery of capacity costs from transportation customers. A PA PUC Order approving the settlement was issued in September

2003.

In the third quarter of 2002, the PA PUC issued an order approving Equitable Gas request for a Delinquency Reduction Opportunity Program. The program gives incentives to eligible delinquent customers to make payments exceeding their current bill amount and to receive additional credits from Equitable Gas to reduce the customer s balance. The program will be fully funded through customer contributions and a surcharge in rates.

In the second quarter 2002, the PA PUC authorized Equitable Gas to offer a sales service that would give residential and small business customers the alternative to fix the unit cost of the commodity portion of their rate.

The program was developed in response to customer requests for a method to reduce the fluctuation in gas costs. This first of its kind program in Pennsylvania is another in a series of service-enhancing initiatives implemented by Equitable Gas. A competitor, Dominion Retail, Inc., appealed the PA PUC order authorizing the new service to the Commonwealth Court of Pennsylvania. In September 2003, the Commonwealth Court of Pennsylvania issued an order affirming the PA PUC decision granting Equitable Gas authority to implement the new Fixed Sales Service. To date, Equitable Gas has not offered Fixed Sales Service but will continue to analyze the feasibility of a Fixed Sales Service in the future.

Equitable Gas completes quarterly purchased gas cost filings with the PA PUC that are subject to quarterly reviews and annual audits by the PA PUC. The PA PUC completed its most recent audit in 2001, which approved the Company s purchased gas costs through 1999. The PA PUC Audit Bureau has commenced an audit of the 2000-2001 purchased gas period. The on-site audit concluded in the fourth quarter of 2003. A final audit report for the 2000-2001 period is expected by the end of the second quarter of 2004. The Company s purchased gas costs for 2000-2003 are currently unaudited by the PA PUC but have received a final prudency review by the PA PUC through 2002 in which no material issues have been noted.

Interstate Pipeline

The interstate pipeline operations of Equitrans and Carnegie Pipeline are subject to rate regulation by the FERC. In 1997, Equitrans filed a general change application (rate case). The rate case was resolved through a FERC approved settlement among all parties. The settlement provided, with certain limited exceptions, that Equitrans not file a general rate increase with an effective date before August 1, 2001, and must file a general rate case application to take effect no later than August 1, 2003. In the second quarter 2002, Equitrans filed with the FERC to merge its assets and operations with the assets and operations of Carnegie Pipeline. In April 2003, Equitrans filed a proposed settlement with the FERC related to the application to merge its assets with the assets of Carnegie Pipeline. The settlement also provided for a deferral to April 2005 of the August 1, 2003 rate case filing requirement. This proposed settlement was broadly supported by most parties. On July 1, 2003, Equitrans received an order from the FERC approving the merger of Equitrans and Carnegie Pipeline but denying the request for deferral of the requirement to file a rate case by August 1, 2003. In response to the July 1, 2003 order Equitrans filed for and received an extension of time for its rate case filing deadline from August 1, 2003 until December 1, 2003. Also in response to the July 1, 2003 order, on January 1, 2004, the merger of Equitrans and Carnegie Pipeline was effectuated with Equitrans surviving the merger.

Equitrans timely filed its rate case application on December 1, 2003. On December 31, 2003, in accordance with the Natural Gas Act, the FERC issued an order accepting in part and rejecting in part Equitrans general rate application. Certain of Equitrans proposed tariff sheets have been accepted subject to a 5-month suspension period, but Equitrans requests for revenue relief were denied. The increase was rejected in large part because Equitrans did not provide cost and revenue data for Carnegie Pipeline. Equitrans is planning to assemble cost and revenue data for Carnegie Pipeline and re-file its rate case application in the first quarter of 2004. Consistent with the Company s original December 1, 2003 filing, Equitrans upcoming rate case application will address several issues including establishing an appropriate return on the Company s capital investments, addressing the Company s pension funding levels, accruing for post-retirement benefits other than pensions and restructuring its storage services. The Company s request for rate relief is expected to be approximately $18.0 million. In conjunction with the Company s application for rate relief, Equitrans filed a rehearing request on January 30, 2004, seeking reconsideration of the FERC s December 31, 2003 order. Equitrans will continue to explore and evaluate settlement options throughout the pendency of the case.

Energy Marketing

Equitable Utilities unregulated marketing operations, Equitable Energy, provides commodity procurement and delivery, risk management and customer services to energy consumers including large industrial, utility, commercial and institutional end-users. Equitable Energy s primary focus is to provide products and services in those areas where the Company has a strategic marketing advantage, usually due to geographic coverage and ownership of physical or contractual assets.

The Company also engages in limited trading activity, with the objective of limiting exposure to shifts in market prices. Equitable Energy uses prudent asset management to optimize the Company s assets through trading activities.

Historically, Equitable Utilities marketing affiliate purchased and resold a portion of Equitable Supply s production. Beginning January 1, 2003, these marketing activities have been recorded directly in Equitable Supply. The change did not have a significant impact on the Company as a whole; however, there was a significant reduction in the marketing revenues and purchased natural gas costs for the unregulated marketing activities recorded in Equitable Utilities.

Capital Expenditures

Equitable Utilities forecasts 2004 capital expenditures to be approximately $58 million, a 3% decrease over actual capital expenditures of approximately $60 million for 2003. The 2004 capital expenditures are expected to include 2003 capital commitments totaling $16 million. The total 2004 capital budget includes $43 million for Utilities infrastructure improvements, $4 million for technology enhancements and $5 million for new business development. The infrastructure improvements include improvements to existing distribution and transmission lines as well as storage enhancements. The technology expenditures are primarily related to mobilization initiatives as well as systems enhancements and integration. The new business capital is planned for distribution extension projects. The Company expects to finance its authorized 2004 expenditure program with cash generated from operations and with short-term financing.

Early in 2004, Equitable Gas successfully implemented a new customer information and billing system for which it incurred $11.8 million of capital expenditures from project inception through December 31, 2003. Total capital expenditures for this project significantly exceeded the original estimate. Though the project exceeded the original estimate, no impairment has been recognized, as the Company believes that all costs related to the project are appropriate and will have future benefit to the Company. The system will be depreciated over a fifteen year period beginning in 2004.

Other

Equitable Gas contract with the members of the local United Steelworkers union expired on April 15, 2003. The Company and the union have agreed to work under the terms of the expired contract while negotiating a new contract.

Results of Operations

Equitable Utilities

In 2002, the Company classified all gains and losses associated with its energy trading activities to a net presentation for all periods presented in accordance with EITF No. 02-3.

	Years Ended December 31,		
	2003	2002	2001

OPERATIONAL DATA			
Total operating expenses as a % of net operating revenues	55.17%	56.33%	65.77%
Capital expenditures (thousands)	$ 60,414	$ 70,188	$ 38,528

FINANCIAL DATA (Thousands)			
Utility revenues (regulated)	$ 408,110	$ 343,847	$ 408,812
Marketing revenues	205,258	410,426	440,246
Total operating revenues	613,368	754,273	849,058
Utility purchased gas costs (regulated)	189,998	131,079	192,109
Marketing purchased gas costs	178,247	389,787	426,207
Net operating revenues	245,123	233,407	230,742
Operating expenses:			
Operation and maintenance expense	51,208	50,335	56,013
Selling, general and administrative expense	56,453	54,249	69,344
Depreciation, depletion and amortization	27,583	26,894	26,404
Total operating expenses	135,244	131,478	151,761
Operating income	$ 109,879	$ 101,929	$ 78,981

Equitable Utilities had operating income of $109.9 million for 2003, compared with $101.9 million for 2002. The increase is primarily attributable to colder weather in the first quarter of 2003 offset somewhat by warmer weather in the second and fourth quarters of 2003. Additionally, Equitable Marketing experienced an increase in wholesale volumes and margins in both the third and fourth quarters of 2003. These items were offset by an increase in provisions for doubtful accounts and a decrease in storage related revenues in the Pipeline operations. The Distribution operations also experienced increased operating costs in the first quarter 2003 related to the repair of leaks and increased emergency calls incurred due to the cold weather.

Capital expenditures decreased $9.8 million to $60.4 million in 2003 from $70.2 million in of 2002. The decrease is primarily due to a reduction in new business development spending and mainline replacement.

Operating income for 2002 was $101.9 million, compared with $79.0 million for 2001. The improved results for 2002 are primarily due to higher revenues resulting from cooler weather in the fourth quarter 2002, non-recurring 2001 charges related to pipeline operations workforce reductions and compressor station automation and an incremental credit related reserve of $7.0 million in 2001.

Capital expenditures increased $31.7 million to $70.2 million in 2002 from $38.5 million in 2001 due to increased infrastructure improvement and technological enhancement projects.

Distribution Operations

	Years Ended December 31,		
	2003	**2002**	**2001**
OPERATIONAL DATA			
Heating degree days (30 year average = 5,829) (a)	5,695	5,258	5,059
O&M per customer (b)	$ 290.35	$ 265.98	$ 296.52
Volumes (MMcf):			
Residential sales and transportation	27,262	25,646	24,753
Commercial and industrial	28,784	29,920	24,500
Total throughput	56,046	55,566	49,253

(a) A heating degree day is computed by taking the average temperature on a given day in the operating region and subtracting it from 65 degrees Fahrenheit. Each degree by which the average daily temperature falls below 65 degrees represents one heating degree day.

(b) O&M is defined for this calculation as the sum of operating expenses (total operating expenses excluding depreciation) less other taxes. Other taxes for the years ended December 31, 2003, 2002 and 2001 totaled $2.4 million, $3.0 million and $3.2 million, respectively. In 2003, 2002 and 2001, there were approximately 274,500 customers, 275,000 customers and 273,000 customers, respectively.

	Years Ended December 31,		
	2003	2002	2001
FINANCIAL DATA (Thousands)			
Residential net operating revenues	$ 109,821	$ 105,323	$ 103,141
Commercial and industrial net operating revenues	50,660	46,846	44,399
Other net operating revenues	4,705	3,924	7,084
Total net operating revenues	$ 165,186	$ 156,093	$ 154,624
Operating expenses (total operating expenses excluding depreciation)	82,068	76,139	84,276
Depreciation, depletion and amortization	20,025	19,933	18,175
Operating income	$ 63,093	$ 60,021	$ 52,173

Net operating revenues for 2003 were $165.2 million compared to $156.1 million in 2002. Heating degree days were 5,695 in 2003, which is 8% cooler than the 5,258 degree days in 2002. The colder weather had a positive year-over-year impact on net operating revenues of approximately $6.3 million. The additional increase in commercial and industrial net operating revenues of $1.7 million is primarily due to increased delivery margins during the first, second, and fourth quarters, despite the 4% decrease in related volumes. The related volumes decreased primarily due to low margin industrial usage and, therefore, had minimal impact on net operating revenues.

Operating expenses increased by $5.9 million in 2003 from $76.1 million in 2002. The primary cause for the increase in expenses is due to an increase of $4.3 million in the provision for doubtful accounts, which was recorded at approximately 5% of residential revenues, combined with higher cold-weather related maintenance costs from the first quarter 2003 for the repair of leaks and increased emergency calls. These increases were offset by on-going cost reduction initiatives.

Net revenues for 2002 were $156.1 million compared to $154.6 million in 2001. Heating degree days were 5,258 for 2002, which is 4% cooler than the 5,059 degree days recorded in 2001 and 12% warmer than the 30-year normal of 5,968 as of 2002. The colder weather had a positive year-over-year impact on net revenues of approximately $2.2 million, which was partially offset by a decrease in late fee revenue due to improved accounts receivable collections. Commercial and industrial volumes increased 22% from 2001 primarily due to the increased sales to steel industry customers. Despite the increase in commercial and industrial volumes, net operating revenues did not proportionately increase due to the relatively low margins on industrial customer volumes.

Operating expenses decreased $8.1 million in 2002, or 10%, from $84.3 million in 2001. The decrease is attributable to a $7.0 million charge for incremental credit-related reserves recorded in the fourth quarter of 2001. The operating expenses were also favorably impacted by reduced operations and maintenance expenses related to continued process improvement initiatives and reduced collection related costs. The reduced operations and maintenance expenses were partially offset by increases in pension and post retirement benefit costs.

Pipeline Operations

	Years Ended December 31,		
	2003	**2002**	**2001**
OPERATIONAL DATA			
Transportation throughput (BBtu)	72,988	70,197	70,693
FINANCIAL DATA (Thousands)			
Net operating revenues	$ 52,926	$ 56,675	$ 62,079
Operating expenses (Total operating expenses excluding depreciation)	23,237	24,744	33,249
Depreciation, depletion and amortization	7,274	6,553	7,872
Operating income	$ 22,415	$ 25,378	$ 20,958

Total transportation throughput increased 2.8 million MMbtu, or 4% in 2003 over the prior year due primarily to colder than normal weather in the first quarter of 2003 that caused many of the firm transportation contract customers to use the full capacity of the pipeline. Those volumes were partially offset by decreased throughput due to warmer than prior year weather in the second and third quarters of 2003. Because the margin from these firm transportation contracts is generally derived from fixed monthly fees, regardless of the volumes transported, the increased throughput did not positively impact net operating revenues.

Net operating revenues from pipeline operations in 2003 decreased to $52.9 million from $56.7 million in 2002. The change in net operating revenues is due almost entirely to a decrease in storage related revenue as a result of firm customer delivery demands in the first quarter of 2003 from colder weather and higher gas prices. In addition, the high gas prices and lower demand in the second, third and fourth quarters of 2003 resulted in the inability to take advantage of commercial opportunities that typically exist.

Operating expenses decreased by $1.5 million to $23.2 million in 2003. The decrease is primarily due to planned maintenance charges related to a pipeline maintenance program recognized in the third quarter of 2002 combined with ongoing cost reduction initiatives.

Net operating revenues from pipeline operations decreased to $56.7 million in 2002 from $62.1 million in 2001. The decrease is related to the transfer of all of its natural gas pipeline gathering systems to the Equitable Supply segment effective January 1, 2002. The transfer resulted in a reduction of $3.6 million in net revenues and $3.1 million in operating costs. The remainder of the decrease in net revenues is due to extraction revenues from the sale of the facilities and unfavorable transportation margins due to competition.

Operating expenses decreased by $8.5 million in 2002 from $33.2 million in 2001. The decreased operating expenses are primarily due to the June 2001 and September 2001 charges for workforce reductions and process improvements related to compressor automation totaling $6.0 million. The cost reductions from the 2001 charges and continued process improvement initiatives favorably impacted the 2002 expenses. These cost savings were offset by the Company s decision to accelerate a pipeline maintenance program. Total operating expenses were also reduced by $3.1 million from the previously mentioned transfer of gathering systems.

Energy Marketing

	Years Ended December 31,		
	2003	2002	2001
OPERATIONAL DATA			
Total throughput (BBtu)	40,430	169,942	215,541
Net operating revenues/Mmbtu	$ 0.6681	$ 0.1214	$ 0.0651
FINANCIAL DATA (Thousands)			
Net operating revenues	$ 27,011	$ 20,639	$ 14,039
Operating expenses (Total operating expenses excluding depreciation)	2,356	3,701	7,832
Depreciation, depletion and amortization	284	408	357
Operating income	$ 24,371	$ 16,530	$ 5,850

Net operating revenues in 2003 increased to $27.0 million from $20.6 million in 2002, or 31%, as a result of increased sales for resale off the Equitable Utilities systems, increased unit marketing margins, and the continued focus on high margin sales through storage optimization and asset management. The Equitable Supply segment assumed the direct marketing of a substantial portion of its operating volumes at the beginning of 2003, which had previously been marketed by Equitable Marketing. These volumes, totaling approximately 138,000 billion British thermal units (Bbtu) in 2003, had been marketed by Equitable Marketing at very low margins. Although the assumption of these volumes by Equitable Supply did not have a significant impact on Equitable Marketing s net operating revenues for the year-ended December 31, 2003, it was the primary reason for the significant increase in the unit marketing margins during that same period.

Operating expenses decreased by $1.3 million from 2002 to 2003 primarily due to the recovery of a bankrupt customer s balance in 2003 that was reserved for in 2002 and a reduction in bad debt expense, as well as continued cost reduction initiatives associated with the Company s decision to de-emphasize low margin trading-oriented activities.

Net revenues for energy marketing operations increased $6.6 million in 2002, or 47%, from $14.0 million in 2001. This increase in net revenues and in unit marketing margins versus 2001 is a result of the Company s decision to focus on storage and asset management activities and continued de-emphasis on the low margin trading oriented activities. This decision resulted in the 21% reduction in marketed gas sales volumes in 2002. These increases were partially offset by losses of $2.6 million on transactions marked to market in 2001.

Operating expenses decreased 52.7% from 2001 to 2002. The decline in operating expenses is associated with a reduction in workforce due to reduced trading activities in 2002, decreased provisions for bad debts attributable to lower gas prices compared to 2001 and reduced costs associated with retail marketing activities.

Equitable Supply

Equitable Supply consists of two activities, production and gathering, with operations in the Appalachian Basin region of the United States. Equitable Production develops, produces and sells natural gas (and minor amounts of associated crude oil and its associated by-products). Equitable Gathering engages in natural gas gathering and the processing and sale of natural gas liquids.

Equitable Supply completed several transactions, which affect the comparability of the financial data between 2003, 2002 and 2001.

Prepaid Natural Gas Sales

During 2000, the Company utilized two prepaid natural gas sales transactions to limit the Company s exposure to commodity volatility, to reduce its counter-party risk, and to raise capital. These contracts are based upon energy content or Btu. The Company converts these to their volumetric equivalents or Mcfe using a factor of 1.05 MMBtu per Mcfe.

In December 2000, Equitable sold approximately 26.1 Bcf of future production for proceeds of $104.0 million. This natural gas advance sales contract is treated as a prepaid forward sale and is recorded as a liability. Under the terms of this sales contract, the Company must deliver approximately 14,300 Mcf per day for five years starting January 1, 2001. The Company recognizes the revenue from this sale as natural gas is gathered and delivered.

In December 2000, Equitable sold approximately 26.6 Bcf of future production for proceeds of $104.8 million. This natural gas advance sales contract is treated as a prepaid forward sale and is recorded as a liability. Under the terms of this sales contract, the Company was required to deliver approximately 24,300 Mcf per day for three years starting January 1, 2001 and ending December 31, 2003. The Company recognized the revenue from this sale as natural gas was gathered and delivered.

The following table details the specifics of the Company s various prepaid transactions. The gathering fee and wellhead price listed are for 2003. The gathering fee received for 2002 and 2001 relating to each transaction was $0.71 per Mcf. The wellhead price received for 2002 and 2001 was $3.28 per Mcf and $3.23 per Mcf for the five and three year contracts, respectively.

Total Contract Volume (Bcf)	**Contract Term**	**Annual Volume (Bcf)**		**Gathering Fee ($ /Mcf)**		**Wellhead Price ($ /Mcf)**		**Annual Revenue (Thousands)**
26.1	5 years	5.2	$	0.72	$	3.27	$	20,794
26.6	3 years	8.9	$	0.72	$	3.22	$	34,922

Sale of Oil Properties

In December of 2001, the Company sold its oil-dominated fields in order to focus on natural gas activities. The sale resulted in a decrease of 63 Bcfe of proved developed producing reserves and 5 Bcfe of proved undeveloped reserves and generated proceeds of approximately $60 million. The field produced approximately 4 Bcfe annually.

Sales of Gas Properties

Occasionally, the Company enters into a sale of gas properties in order to reduce its exposure to commodity volatility, to reduce counter-party risk, to eliminate production risk, and to raise capital, while providing the Company market-based fees associated with the gathering, marketing, and operation of these producing properties.

In June 2000, Equitable sold properties with 66.0 Bcfe of reserves qualifying for the nonconventional fuels tax credit to a partnership, Eastern Seven Partners, L.P. (ESP), for proceeds of approximately $122.2 million and a retained interest in the partnership. This sale of gas properties reduced the natural gas production revenue and reserves reported in subsequent years. The Company retained an interest in the partnership that is recorded as equity in nonconsolidated investments on the Consolidated Balance Sheet under the equity method of accounting. Under the terms of the transaction, the Company s equity interest will increase under certain circumstances upon achieving

certain production goals. The Company separately negotiated arms-length, market-based rates for gathering, marketing and operating fees with the partnership in order to deliver the partnership s natural gas to the market. The underlying contracts associated with these fees are subject to annual renewal after an initial term. As the operator of the gas properties in the partnership, the Company may from time to time have receivables outstanding from ESP of up to $10 million. As of December 31, 2003 and 2002, the Company had receivables outstanding from ESP totaling $0.1 million and $0.2 million, respectively.

In December 2000, Equitable sold properties with 133.3 Bcfe of reserves to a trust, Appalachian Natural Gas Trust (ANGT), for proceeds of approximately $255.8 million and a retained interest in the trust. This sale of gas properties reduced the natural gas production revenue and reserves reported in subsequent years. The Company retained an interest in the trust, which is recorded as equity in nonconsolidated investments on the Consolidated Balance Sheet under the equity method of accounting. Under the terms of the transaction the Company s equity interest will increase under certain circumstances upon achieving certain production goals. The Company separately negotiated arms-length, market-based rates for gathering, marketing and operating fees with the trust in order to deliver the trust s natural gas to the market. The underlying contracts associated with these fees are subject to annual renewal. As the operator of the gas properties and as a result of a separate agreement, the Company receives a market-based fee for providing a restricted line of credit to the trust that is limited by the fair market value of the trust s remaining reserves.

Below is a table that details information associated with the Company s sales of gas properties in 2000 to ESP and ANGT as of December 31, 2003, 2002 and 2001.

Sales of Gas Properties	**Reserves Sold (Bcfe)**	**Volumes Produced (Bcfe)**			**Revenue Recognized from Fees (Thousands)**		
		2003	**2002**	**2001**	**2003**	**2002**	**2001**
ESP	66.0	9.0	9.6	10.3	$ 8,619	$ 8,522	$ 8,876
ANGT	133.3	13.6	14.2	15.4	$ 15,053	$ 15,442	$ 16,130

In February 2003, the Company sold approximately 500 of its low-producing wells, within two of its non-strategic districts, in two separate transactions. The sales resulted in a decrease of approximately 13 Bcf of net reserves for proceeds of approximately $6.6 million. The wells produced an aggregate of approximately 1.0 Bcf in 2002. The Company did not recognize a gain or a loss as a result of this disposition.

Appalachian Basin Partners, LP

In November 1995, the Company monetized Appalachian gas properties qualifying for the nonconventional fuels tax credit to a partnership, Appalachian Basin Partners, LP (ABP). The Company recorded the proceeds as deferred revenue, which was recognized as production occurred. The Company retained a partnership interest in the properties that increased substantially at the end of 2001 based on the attainment of a performance target. Beginning in 2002, the Company no longer included ABP volumes as monetized sales, but instead as equity production sales. As a result, monetized sales volumes decreased by approximately 8.8 Bcf from 2001 to 2002 while net equity sales volumes increased by the same amount. The Company consolidated the partnership starting in 2002, and the remaining portion not owned by the Company was recorded as minority interest.

As a result of the Company s increased partnership interest in ABP in 2002, the Company began receiving a greater percentage of the nonconventional fuels tax credit attributable to ABP. This resulted in a reduction of the Company s effective tax rate during 2002. The nonconventional fuels tax credit expired at the end of 2002 and it is currently unclear whether legislation will be enacted to allow this tax benefit to exist in the future.

In February 2003, the Company purchased the remaining 31% limited partnership interest in ABP from the minority interest holders for $44.2 million. The 31% limited partnership interest represented approximately 60.2 Bcf of reserves. As a result, effective February 1, 2003, the Company no longer recognizes minority interest expense associated with ABP, which totaled $0.9 million and $7.1 million for the years ended December 31, 2003 and 2002, respectively. This transaction was approved by the Company s Board of Directors separate from Equitable Supply s original 2003 capital budget program and was financed through short-term financing.

Capital Expenditures

Equitable Supply forecasts its 2004 capital expenditures to be approximately $138 million. This includes $85 million for the development of Appalachian holdings and $53 million for improvements and extensions to gathering system pipelines. The $41.0 million decrease in the development of Appalachian holdings from 2003 to 2004 is to allow Equitable Supply to concentrate on its core assets and insure a proper level of return related to all new projects. The evaluation of new development locations, market forecasts and price trends for natural gas and oil will continue to be the principal factors for the economic justification of drilling and gathering system investments. The Company expects to finance its authorized 2004 expenditure program with cash generated from operations and with short-term financing. Capital expenditures increased from $147.5 million in 2002 to $204.5 million in 2003 primarily as a result of an increase in the level of development drilling in the Appalachian holdings and the purchase of the remaining limited partnership interest in ABP for $44.2 million. The capital expenditures in 2003 and 2002 included $126.0 million and $114.4 million, respectively, for the development of Appalachian holdings and $34.3 million and $33.1 million, respectively, for gathering system improvements and extensions.

Other

On October 15, 2003, the Company and the Paper, Allied-Industrial, Chemical and Energy Workers Industrial Union Local 5-512 reached agreement on a new five-year contract. The union workforce provides pipeline and compression services and contract well tending services to Equitable Supply in Kentucky. The terms of the contract mandated increased wages and pension benefits, which will be offset in the Company s results of operations by decreases in overtime.

In 2004, Equitable Supply will focus on four main objectives to increase production and sales of natural gas. These four objectives are: (1) reducing bottom hole pressure in each well to the minimum level possible to eliminate impediments to natural gas flow; (2) lowering field pressure to the minimum level that can be economically justified; (3) reducing lost gas to the minimum level that can be justified economically and not accepting unaccounted for gas; and (4) drilling the Company s remaining undeveloped acreage quickly and efficiently to deliver the Company s gas reserves to market.

Equitable Supply

Operational and Financial Data

	Years Ended December 31,		
	2003	**2002**	**2001**
OPERATIONAL DATA			
Total sales volumes (MMcfe) (a)	64,306	61,719	61,670
Capital expenditures (thousands) (b)	$ 204,527	$ 147,461	$ 93,862

(a) Includes equity sales volumes and monetized sales volumes.

(b) 2003 capital expenditures include the purchase of the remaining 31% limited partnership interest in ABP ($44.2 million) which was separately approved by the Board of Directors of the Company in addition to the total amount originally authorized for the 2003 capital budget program.

	Years Ended December 31,		
	2003	**2002**	**2001**
FINANCIAL DATA (Thousands)			
Production revenues	$ 262,607	$ 225,713	$ 240,680
Gathering revenues	69,827	63,279	61,598

Total net operating revenues		332,434		288,992		302,278
Operating expenses:						
Lease operating expenses, excluding severance taxes		21,454		18,141		21,855
Severance tax		13,409		8,123		10,640
Land and leasehold maintenance		824		847		2,005
Gathering and compression (operation and maintenance)		25,110		23,095		24,594
Selling, general and administrative (SG&A)		27,094		26,873		24,556
Depreciation, depletion and amortization (DD&A)		48,748		40,711		40,624
Total operating expenses		136,639		117,790		124,274
Operating income	$	195,795	$	171,202	$	178,004
Equity in earnings of nonconsolidated investments	$	431	$	282	$	726
Minority interest	$	(871)	$	(7,103)	$	

Equitable Supply s operating income for 2003 totaled $195.8 million, 14% higher than the $171.2 million earned in 2002. The segment s 2003 net operating revenues were $332.4 million, 15% higher than the 2002 net operating revenues of $289.0 million. The increases in Equitable Supply s operating income and net operating revenues were primarily the result of a 13% higher average well-head sales price, a 5% increase in equity volumes, and a 10% increase in gathering revenues, the total of which for operating income was partially offset by increased operating expenses.

Equitable Supply s average well-head sales price realized on produced volumes for 2003 was $3.91 per Mcfe compared to $3.47 per Mcfe for 2002. The $0.44 per Mcfe increase in the average well-head sales price was attributable to higher gas commodity prices, increased volumes at higher hedged prices and increased basis over the same period in 2002. The 5% increase in equity volumes was primarily the result of new wells drilled in 2002 and 2003 and production enhancements partially offset by the normal production decline in the Company s wells and the Company s sale in February 2003 of approximately 500 of its low-producing wells within two of its non-strategic districts. Those wells produced an aggregate of approximately 1.0 Bcf in 2002. The 10% increase in revenues from gathering fees was attributable to an 8% increase in the average gathering rate billed to equity and third party customers in addition to an increase in the segment s equity and third party gathered volumes.

Total operating expenses were $136.6 million for 2003 compared to $117.8 million for 2002. The 16% increase was primarily attributable to an increase in lease operating expenses, severance taxes, higher depreciation, depletion and amortization expenses (DD&A) resulting from a $0.09 per Mcfe increase in the unit depletion rate and increased production volumes, and higher gathering and compression expenses mainly attributable to an increase in gathering fees paid to third parties. The increase in severance taxes is primarily attributable to higher gas commodity prices. The increase in lease operating expenses is primarily the result of an increase in road maintenance and other repair costs due to severe weather and flooding in 2003, and increases in property taxes and liability insurance premiums.

The decrease in minority interest expense of $6.2 million from $7.1 million in 2002 is due to the purchase of the remaining 31% limited partnership interest in ABP from the minority interest holders in February 2003. Beginning in 2002, the Company consolidated ABP, with the portion not owned by the Company being recorded as minority interest. As a result of the Company s purchase of the remaining 31% limited partnership interest in ABP, effective February 1, 2003, Equitable Supply no longer recognizes minority interest expense associated with ABP.

Equitable Supply had operating income of $171.2 million for 2002, compared with $178.0 million in 2001. The lower results for 2002 are primarily due to a $0.25 per Mcfe reduction in the average well-head sales price partially offset by an increase in gathering revenues and a net reduction in operating expenses. The net reduction in operating expenses is the result of a decrease in the severance tax component of production and leasehold expenses attributable to lower gas commodity prices, reduced well-tending expenses, lower leasehold costs resulting from improved acreage management, and lower gathering and compression expenses, the total of which was partially offset by a $2.3 million increase in SG&A expenses.

SG&A costs remained consistent from 2002 to 2003 as a result of a reduction in legal claims and reserves being offset by a $2.0 million loss incurred during 2003 on the early termination of an uneconomic sales contract. SG&A expenses for 2002 increased from the same period in 2001 due to $3.5 million of costs associated with legal claims and reserves partially offset by productivity improvements.

Total sales volumes for 2003 have increased 2.6 Bcfe compared to 2002. While total sales volumes have increased, the amount of the increase has not met the Company s expectations primarily due to volume shortfalls in the southern West Virginia region. Some of the shortfall versus the Company s expectations is related to well performance issues caused by wells drilled in 2002 in less productive areas of the region and negative impacts related to new automation technology and well surveillance. The remaining shortfall is due to more pipeline system curtailments than were forecasted and delays in the timing of pressure optimization and production enhancement projects. As a result, the Company has executed organizational changes that include assigning more engineers directly to operating districts to address production and performance issues through well surveillance initiatives and a reengineered predictive maintenance program. In addition, the Company has taken actions, in the form of adding more firm transportation on the interstate pipeline systems, implementing new pipeline projects to increase the pipeline take away capacity and reliability, and performing historical pipeline and measurement studies to help the Company track and target future shortfalls on an accelerated basis. The Company has also shifted drilling capital to areas where overall results are more predictable and has reduced the overall level of capital in the 2004 capital budget related to the development of its Appalachian holdings as compared to 2003 to allow Equitable Supply to concentrate on its core assets and ensure a proper level of return related to all new projects.

Equitable Production

Operational and Financial Data

	Years Ended December 31,		
	2003	**2002**	**2001**
OPERATIONAL DATA			
Net equity sales, natural gas and equivalents (MMcfe) (a)	50,227	47,640	38,825
Average (well-head) sales price ($/Mcfe)	$ 4.10	$ 3.53	$ 3.67
Monetized sales (MMcfe) (b)	14,079	14,079	22,845
Average (well-head) sales price ($/Mcfe)	$ 3.23	$ 3.27	$ 3.81
Total sales volumes (MMcfe)	64,306	61,719	61,670
Average (well-head) sales price ($/Mcfe)	$ 3.91	$ 3.47	$ 3.72
Company usage, line loss (MMcfe) (a)	5,501	6,216	5,742
Natural gas inventory, December 31 (MMcfe)	112		
Natural gas and oil production (MMcfe) (c)	69,919	67,935	67,412
Operated volumes - third parties (MMcfe) (d)	22,619	23,858	25,755
Lease operating expense (LOE), excluding severance tax ($/Mcfe)	$ 0.31	$ 0.27	$ 0.32
Severance tax ($/Mcfe)	$ 0.19	$ 0.12	$ 0.16
Production depletion ($/Mcfe)	$ 0.49	$ 0.40	$ 0.38
Depreciation, depletion and amortization (in thousands):			
Production depletion	$ 33,911	$ 26,970	$ 25,785
Other depreciation, depletion and amortization	2,063	1,417	2,680
Total depreciation, depletion and amortization	$ 35,974	$ 28,387	$ 28,465

(a) Effective January 1, 2003, the Company adjusted its method for using a natural gas equivalents conversion factor to convert gallons of liquid hydrocarbon sales to equivalent volumes of natural gas sales. This change results in an additional 0.3 Bcfe natural gas sales volume and a corresponding reduction to reported Company usage and line loss for the year ended December 31, 2003.

(b) Volumes sold associated with the Company s two prepaid natural gas sales contracts and the ABP partnership discussed above.

(c) 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.

(d) Includes volumes in which interests were sold but which the Company still operates for third-parties for a fee. See the ESP and ANGT table in the Sale of Gas Properties section for additional information.

	Years Ended December 31,		
	2003	2002	2001
FINANCIAL DATA (Thousands)			
Net equity sales	$ 206,116	$ 168,225	$ 142,409
Monetized sales	45,542	46,000	86,935
Other revenue	10,949	11,488	11,336
Total production revenues	262,607	225,713	240,680
Operating expenses:			
Lease operating expense, excluding severance taxes	21,454	18,141	21,855
Severance tax	13,409	8,123	10,640
Land and leasehold maintenance	824	847	2,005
Selling, general and administrative (SG&A)	18,562	18,926	16,207
Depreciation, depletion and amortization (DD&A)	35,974	28,387	28,465
Total operating expenses	90,223	74,424	79,172
Operating income	$ 172,384	$ 151,289	$ 161,508
Equity earnings from nonconsolidated investments	$ 431	$ 282	$ 726
Minority interest/other	$ (871)	$ (7,103)	$

Equitable Production s total production revenues, which are derived primarily from the sale of produced natural gas, increased $36.9 million from 2002 to 2003. The increase is primarily the result of a $37.4 million increase in the total of net equity and monetized sales from 2002 due to a higher average well-head sales price of $3.91 per Mcfe compared to $3.47 per Mcfe in the prior year ($28.5 million) and increased sales volumes ($8.9 million). The increase in sales volumes is the result of new wells drilled in 2002 and 2003 and production enhancements, partially offset by the normal production decline in the Company s wells and the Company s sale in February 2003 of approximately 500 of its low-producing wells within two of its non-strategic districts in two separate transactions. The wells sold produced an aggregate of approximately 1.0 Bcf in 2002. The Company did not recognize a gain or loss as a result of this disposition.

Operating expenses increased $15.8 million or 21% over the prior year from $74.4 million to $90.2 million. This increase was primarily due to increased DD&A costs ($7.6 million), higher severance taxes attributable to higher natural gas prices ($5.3 million), and increased lease operating expenses ($3.3 million). The increase in DD&A was due to a $0.09 per Mcfe increase in the unit depletion rate ($6.2 million) and increased production volumes and other depreciation ($1.4 million). The $0.09 per Mcfe increase in the unit depletion rate is comprised of a $0.03 per Mcfe increase from 2002 drilling costs, a $0.03 per Mcfe increase due to the February 2003 acquisition of the ABP limited partnership interest, and a $0.03 per Mcfe increase due to the January 1, 2003 adoption of Statement No. 143. The increase in lease operating expenses is primarily the result of higher road maintenance due to severe weather and flooding in 2003 and other repair costs ($1.5 million), an increase in property taxes and liability insurance premiums ($1.1 million), and an increase in well maintenance and well surveillance costs ($0.4 million).

Total production revenues decreased $15.0 million from 2001 to 2002. The decrease in total production revenues is due primarily to lower effective commodity prices ($15.3 million) and sales of oil properties ($17.0 million), partially offset by increased production from new drilling ($15.5 million) and production enhancements ($1.4 million).

Operating expenses for the period ended December 31, 2002 decreased 6.0% as compared to the same period in 2001. This decrease was primarily due to a 17.0% decrease in lease operating expense resulting from reduced well-tending expenses and a 23.7% decrease in severance taxes, which was primarily due to declines in the market commodity sales price. Land and leasehold maintenance costs were also lower, as a result of lower delay rental costs due to improved acreage management.

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Equitable Gathering

Operational and Financial Data

	Years Ended December 31,		
	2003	2002	2001
OPERATIONAL DATA			
Gathered volumes (MMcfe)	126,674	123,581	106,832
Average gathering fee ($/Mcfe) (a)	$ 0.55	$ 0.51	$ 0.58
Gathering and compression expense ($/Mcfe)	$ 0.20	$ 0.19	$ 0.23
Gathering and compression depreciation ($/Mcfe)	$ 0.09	$ 0.09	$ 0.10
Depreciation, depletion and amortization (in thousands):			
Gathering and compression depreciation	$ 11,711	$ 11,594	$ 10,779
Other depreciation, depletion and amortization	1,063	730	1,380
Total depreciation, depletion and amortization	$ 12,774	$ 12,324	12,159

(a) Revenues associated with the use of pipelines and other equipment to collect, process and deliver natural gas from the field where it is produced, 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.

	Years Ended December 31,		
	2003	2002	2001
FINANCIAL DATA (Thousands)			
Gathering revenues	$ 69,827	$ 63,279	$ 61,598
Operating expenses:			
Gathering and compression expense	25,110	23,095	24,594
Selling, general and administrative (SG&A)	8,532	7,947	8,349
Depreciation, depletion and amortization	12,774	12,324	12,159
Total operating expenses	46,416	43,366	45,102
Operating income	$ 23,411	$ 19,913	$ 16,496

Equitable Gathering s total operating revenues increased $6.5 million or 10.3% from $63.3 million in 2002 to $69.8 million in 2003. The increase was primarily attributable to an 8% rise in the average gathering fee billed to equity and third party customers in addition to a 3.1 Bcfe increase in gathered volumes resulting from higher Equitable Production volumes and new third party customers in southern West Virginia.

Total operating expenses increased to $46.4 million in 2003 from $43.4 million in 2002, a 7% increase year over year primarily due to higher third party gathering costs ($1.5 million), other gathering and compression increases ($0.5 million) and higher depreciation ($0.5 million) relating to capital expenditures for gathering system improvements and extensions.

Equitable Gathering revenues increased 2.7% from 2001 to 2002, primarily due to a 15.7% increase in gathered volumes offset by a 12.1% decrease in the average gathering fee per Mcfe. The increase in gathered volumes is primarily due to the transfer of the Equitrans gathering pipeline system from the Equitable Utilities segment. The decrease in average gathering fees per Mcfe is a result of a below market rate on the Equitrans gathering pipeline system resulting from the FERC approved spin down.

Total operating expenses for the year ended December 31, 2002 decreased 3.8% from the same period in 2001 despite the 15.7% increase in gathered volumes. This decrease was mainly attributable to a 6.1% decrease in gathering and compression costs primarily due to a reduction in third party gathering costs.

NORESCO

NORESCO provides an integrated group of energy-related products and services that are designed to reduce its customers operating costs and improve their energy efficiency. The segment s activities are comprised of performance contracting, energy efficiency programs, combined heat and power and central boiler/chiller plant development, design, construction, ownership and operation. NORESCO s customers include governmental, military, institutional, commercial and industrial end-users. NORESCO also develops, constructs and operates facilities in the United States and operates private power plants in selected international countries.

	Years Ended December 31,		
	2003	2002	2001
OPERATIONAL DATA			
Revenue backlog at December 31 (thousands)	$ 134,195	$ 118,224	$ 128,264
Gross profit margin	24.0%	21.2%	22.0%
SG&A as a % of revenue	13.3%	12.4%	14.7%
Capital expenditures (thousands)	$ 307	$ 698	$ 289

	Years Ended December 31,		
	2003	2002	2001
FINANCIAL DATA (Thousands)			
Energy service contract revenues	$ 170,703	$ 190,107	$ 157,379
Energy service contract costs	129,689	149,801	122,790
Net operating revenue (gross profit margin)	41,014	40,306	34,589
Operating expenses:			
Selling, general and administrative	22,667	23,521	23,112
Impairment of long lived assets		5,320	
Depreciation, depletion and amortization	1,416	1,618	5,952
Total operating expenses	24,083	30,459	29,064
Operating income	$ 16,931	$ 9,847	$ 5,525
Equity in earnings of nonconsolidated investments	$ 2,470	$ 4,699	$ 7,555
Impairment of nonconsolidated investment	$ (11,059)	$	$
Minority interest	$ (542)	$	$

Revenues decreased to $170.7 million in 2003 from $190.1 million in 2002, a decrease of $19.4 million, or 10.2%. This decrease is due primarily to decreased construction activity of energy infrastructure projects versus the prior year. Gross profit margins increased to 24.0% in 2003 from 21.2% in 2002, reflecting a change in the mix of projects constructed during the year. Gross profit margin in 2002 included a demand side management program termination of $2.4 million. Gross profit margins trended upwards over the last year due to the focus on more profitable projects especially in the performance contracting contracts and away from less profitable energy infrastructure construction.

Revenue backlog increased to $134.2 million at year-end 2003 from $118.2 million at year-end 2002. The increase in backlog was primarily due to the award of federal government contracts in 2003.

Total operating expenses decreased by $6.4 million from $30.5 million in 2002 to $24.1 million in 2003. This decrease was primarily due to the $5.3 million impairment charge for the Jamaica power plant project in 2002 as more fully discussed below. Additionally, SG&A expenses decreased to $22.7 million in 2003 from $23.5 million in 2002. Included in SG&A expenses in 2003 was $0.8 million related to the consolidation of the energy infrastructure and performance contracting groups and included in 2002 was $1.0 million related to office consolidations. The remaining $0.6 million decrease in SG&A is primarily due to a reduction in labor costs.

Equity earnings of nonconsolidated investments of $2.5 million in 2003 and $4.7 million in 2002 reflects NORESCO s share of the earnings from its equity investments in power plant assets. The decrease in earnings was primarily due to decreased earnings from the Petroelectrica de Panama LDC Panamanian power plant because of the expiration of its power purchase agreement. Revenue in 2003 from a replacement agreement has been lower than that recognized in 2002. Earnings were also lower due to the consolidation of Hunterdon Cogeneration, LP (Hunterdon) and Plymouth Cogeneration, LP (Plymouth) in the current year. These consolidations, as more fully described in Note 9 to the consolidated financial statements, required NORESCO to recognize minority interest of $0.5 million in 2003.

During the fourth quarter of 2003, the Company reviewed its equity investment in Petroelectrica de Panama LDC, an independent power plant project in Panama, for impairment. See Critical Accounting Policies Involving Significant Estimates for discussion of the analysis, which resulted in an impairment charge for the full value of the investment of $11.1 million.

Revenues increased to $190.1 million in 2002 from $157.4 million in 2001, an increase of $32.7 million, or 20.8%. This increase was due primarily to increased construction activity versus the prior year. Gross profit margins decreased to 21.2% in 2002 from 22.0% in 2001, reflecting a change in the mix of projects constructed during the year. Gross profit margins decreased due to competitive pressures and focus on larger projects with lower gross margins.

Revenue backlog decreased to $118.2 million at year-end 2002 from $128.3 million at year-end 2001. The decrease in backlog was primarily attributable to delays in the awarding of government contracts.

Total operating expenses increased to $30.5 million in 2002 from $29.1 million 2001. During the second quarter 2002, the Company reviewed the Jamaica power plant project related to the NORESCO operating segment for impairment as the project had not been operating to expected levels and repeated remediation efforts were unsuccessful. The Company owned 91.2% of the equity in the project and therefore consolidated the project in its financial statements for 2002. As a result of the Company s review, an impairment loss of $5.3 million was recorded in 2002 to adjust the project assets to their fair value. During the first quarter of 2003, the plant shut down its engines and terminated most of the staff in order to preserve available cash while discussions among the various parties involved in the project continued, seeking a global settlement. In April of 2003, ERI JAM, LLC, owner of the Company s interest in the Jamaica power plant project, filed for bankruptcy protection under Chapter 11 in U.S. Bankruptcy Court (Delaware). In the third quarter 2003, ERI JAM, LLC transferred control under the partnership agreement to the other general partner. Upon adoption of FIN No. 46, it was determined that Jamaica was a variable interest entity and that the Company was not the primary beneficiary. As a result, the Company deconsolidated Jamaica effective July 1, 2003.

Partially offsetting the increase in operating expenses from the impairment charge, depreciation, depletion and amortization expense decreased from 2001 to 2002 by $4.3 million, primarily due to the elimination of goodwill amortization of $3.7 million in accordance with Statement No. 142. SG&A expenses increased slightly to $23.5 million in 2002 from $23.1 million in 2001. Included in SG&A expenses in both 2002 and 2001 were $1.0 million related to office consolidations.

Equity earnings of nonconsolidated investments of $4.7 million in 2002 and $7.6 million in 2001 reflects NORESCO s share of the earnings from its equity investments in power plant assets. The decrease in earnings was primarily due to decreased earnings in a power plant in Panama and another one in Rhode Island.

Other Income Statement Items

	Years Ended December 31,		
	2003	2002	2001
		(Thousands)	
Charitable foundation contribution	$ (9,279)	$	$
Gain on sale of Westport stock	13,985		
Equity in earnings (loss) of Westport	3,614	(8,476)	17,820

In the first quarter of 2003, the Company established a community giving foundation to facilitate the Company s charitable giving program for approximately 10 years. The foundation was funded through a

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contribution of 905,000 shares of Westport resulting in a charge of $9.3 million to earnings, with a one-time tax benefit of approximately $7.1 million (see Note 6 to the Company s consolidated financial statements).

The Company reported $3.6 million in equity earnings from its minority ownership in Westport during the first quarter 2003. At the end of the first quarter of 2003, the Company s ownership position in Westport decreased below 20%. As a result of the decreased ownership, the Company changed the accounting treatment for its investment from the equity method to the available for sale method effective March 31, 2003.

During the fourth quarter 2003, the Company sold approximately 1.48 million shares of Westport, resulting in a capital gain of $14.0 million. As of December 31, 2003, the Company owned 11.53 million shares of Westport.

Interest Expense

	Years Ended December 31,		
	2003	2002	2001
		(Thousands)	
Interest expense	$ 45,766	$ 38,787	$ 41,098

Interest expense increased from 2002 to 2003 primarily due to the issuance of $200 million of Notes in November 2002 and the issuance of $200 million of Notes in February 2003. The stated interest rate for both issuances is 5.15%. The increase was partially offset by the redemption of $125 million of 7.35% trust preferred capital securities on April 23, 2003 as well as lower interest rates on short-term debt.

Interest expense decreased from 2001 to 2002 primarily due to the decrease in interest rates on short-term debt. This decrease was partially offset by the higher interest expense associated with the new long-term notes issued in November 2002.

Average annual interest rates on the Company s short-term debt were 1.2%, 1.8% and 4.1% for 2003, 2002, and 2001, respectively.

Other Items

Cumulative Effect of Accounting Change

Effective January 1, 2003, the Company adopted Statement No. 143 which requires that the fair value of a liability for an asset retirement obligation be recognized by the Company at the time the obligation is incurred. The adoption of Statement No. 143 by the Company resulted in an after-tax charge to earnings of $3.6 million, which is reflected as the cumulative effect of accounting change in the Company s Statement of Consolidated Income for the year ended December 31, 2003.

In accordance with the requirements of Statement No. 142, the Company tested its goodwill for impairment as of January 1, 2002. The Company s goodwill balance as of January 1, 2002 totaled $57.2 million and was entirely related to the NORESCO segment. The fair value of the Company s goodwill was estimated using discounted cash flow methodologies and market comparable information. As a result of the impairment test, the Company recognized an impairment of $5.5 million, net of tax, to reduce the carrying value of the goodwill to its estimated fair value as the level of future cash flows from the NORESCO segment were expected to be less than originally anticipated. In accordance with Statement No. 142, this impairment adjustment was reported as the cumulative effect of accounting change in the Company s Statement of Consolidated Income for the year ended December 31, 2002. In the fourth quarter of 2003 and 2002, the Company performed the required annual impairment test of the carrying amount of goodwill and no further impairment was required.

Income from Discontinued Operations

In April 1998, management adopted a formal plan to sell the Company s natural gas midstream operations. A capital loss in connection with the sale was treated as a nondeductible item for tax reporting purposes under the then current Treasury regulations embodying the loss disallowance rule, resulting in additional tax recorded on this sale as a reduction to net income from discontinued operations. In May 2002, the IRS issued new Treasury regulations interpreting the loss disallowance rule that permitted this capital loss to be treated as deductible. During June 2002, the Company filed amended 1998 tax return filings. Consequently, in the second quarter 2002, the Company recorded a $9.0 million increase in net income from discontinued operations related to this unexpected tax benefit. The amended tax return filings are being reviewed during an ongoing regular examination by the IRS of the Company s tax filings for the 1998 tax year.

Capital Resources and Liquidity

Operating Activities

Cash flows provided by operating activities totaled $121.0 million in 2003 as compared to $214.5 million in 2002. The $93.5 million decrease in operating cash flows from 2002 to 2003 is primarily the result of the decrease in cash provided from working capital due to a large increase in inventory during 2003 as compared to a slight decrease in inventory during 2002. The increase in inventory was mainly due to increased natural gas prices and volumes stored in the current year compared to prior year. In addition, the Company made $51.8 million in pension contributions during 2003.

These decreases were partially offset by an increase in income from continuing operations before cumulative effect of accounting change, as adjusted to net cash provided by operating activities, primarily due to the performance of the Company s operating segments as previously described. Current taxes were lower as a result of an increase in drilling and development costs for which deferred taxes were provided.

When the prepaid gas forward sale transactions were consummated, the Company reviewed the specific facts and circumstances related to these transactions to determine if the appropriate Statement of Cash Flows presentation would be as an operating activity or a financing activity. The Company concluded that the appropriate accounting presentation of the prepaid gas forward sales transactions was as an operating cash flow item. Consistent with the Company s previous presentation, the current presentation includes recognition of monetized production revenues related to prepaid forward gas sales in operating activities. The amount for the both the years ended December 31, 2003 and 2002 is $55.7 million.

Cash flows provided by operating activities totaled $214.5 million in 2002 compared to $129.9 million in 2001. The $84.6 million increase in operating cash flows from 2001 to 2002 is primarily the result of the Company s increased partnership interest in ABP in 2002, in addition to a $36.9 million increase in cash flows from income from continuing operations before cumulative effect of accounting change excluding undistributed earnings from nonconsolidated investments, minority interest, and an impairment of long-lived assets. The combined change in accounts receivable and unbilled revenues, inventory, and accounts payable did not significantly impact the net amount of cash provided by operating activities.

Investing Activities

Net cash flows used in investing activities totaled $214.3 million in 2003 as compared to $169.2 million in 2002 and $125.8 million in 2001.

The Company expended approximately $265.7 million in 2003 for capital expenditures as compared to $218.5 million in 2002 and $132.7 million in 2001. Equitable Supply spent $204.5 million in 2003, of which $125.9 million was spent on developmental drilling, $34.4 million was spent on infrastructure projects and $44.2 million was used for the purchase of the remaining limited partnership interest in ABP in February 2003. The ABP transaction was approved by the Company s Board of Directors separately from the capital expenditure program and was financed through short-term financing. Equitable Utilities spent $60.4 million in 2003, of which $42.4 million was spent on infrastructure projects, $13.3 million was spent on technology projects, $4.1 million was spent on business development and $0.6 million on other capital items.

Also in 2003, there were several investing activities that provided cash. The sale of approximately 1.48 million shares of Westport stock in the fourth quarter of 2003 provided $38.4 million of proceeds. In addition, proceeds of $4.4 million were provided by the sale of the Company s 50% interest in an equity investment in October 2003 and proceeds of $6.6 were provided by the sale of wells in Ohio in February 2003. These proceeds were used for general corporate purposes including the funding of the Company s pension contribution during 2003.

Cash used in 2002 investing activities included $17.6 million invested in available-for-sale securities intended to fund plugging and abandonment and other liabilities for which the Company self-insures.

Cash provided by investing activities in 2001 included $63.0 million of proceeds from the oil-dominated field sale within Equitable Supply. These proceeds were held in a restricted cash account at December 31, 2001 for use in a potential like-kind exchange for certain identified assets. During 2002, the restrictions lapsed and the cash was made available for operations.

A total of $221 million was authorized for the 2004 capital budget program, as previously described in the business segment results. The Company expects to finance this program 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

Net cash flows provided by financing activities totaled $112.9 million in 2003 as compared to $57.2 million of cash flows used in financing activities in 2002 and $26.5 million of cash flows used in financing activities in 2001.

The increase in cash flows provided by financing activities from 2002 to 2003 is primarily the result of increased borrowing in the current year. Short-term borrowing activity resulted in a net cash inflow of $93.6 million in 2003 compared to a net cash outflow of $169.4 million in the prior year. In 2002, the $200 million long-term debt issuance in November 2002 was used to repay a significant portion of commercial paper and short-term loans. The increase in cash flows from short-term borrowing activity was partially offset by a decrease in cash provided by long-term debt as compared to the prior year. The Company issued $200 million of notes in February 2003 with a stated interest rate of 5.15% and a maturity date of March 2018. The proceeds from this issuance were used to retire the Company s $125 million of 7.35% Trust Preferred Securities on April 23, 2003. This provided a net cash increase from the long-term debt issuance of $75 million in 2003 compared to a $200 million increase in 2002 relating to the November 2002 issuance of 5.15% notes. Other repayments and retirements of long-term debt were $24.7 million in 2003 compared to $0.6 million in 2002. Additionally, loan proceeds received from financial institutions associated with the sale of contract receivables were $45.5 million in 2003 compared to $23.2 million in 2002.

Other items impacting cash flows from financing activities for 2003 and 2002 include the Company s purchase of shares of its outstanding stock, proceeds from the issuance of employee stock options and the payment of dividends through the use of cash provided by operating activities. During 2003 and 2002, the Company repurchased 1.4 million and 2.9 million shares of its outstanding common stock for $55.2 million and $97.0 million, respectively. Of the 18.8 million total shares authorized for repurchase, the Company has repurchased approximately 16.7 million shares through December 31, 2003. Proceeds from the issuance of employee stock options were $39.1 million in 2003 compared to $28.5 million in 2002 and $6.9 million in 2001. Additionally, during 2003, 2002, and 2001, the Company paid dividends on its common shares totaling $60.4 million, $41.8 million, and $40.4 million, respectively.

The increase in cash used in financing activities from 2001 to 2002 is primarily the result of an $82.2 million reduction of proceeds received from financial institutions associated with the sale of contract receivables during 2002 offset by the net of the proceeds from issuance of $200 million of long-term debt in the fourth quarter of 2002 to pay down commercial paper and $142.6 million reduction in short-term loans. The additional payments on the proceeds received from financial institutions associated with the transfer of contract receivables is primarily the result of the significant amount of transfers done in 2001 and the fact that certain of the Company s debt covenants limit the amount of contract receivables that can be outstanding at any point in time. The $200 million of long-term debt issued in 2002 has a stated interest rate of 5.15% and is due in November 2012.

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. Short-term loans are used to support working capital requirements during the summer months and are repaid as natural gas is sold during the heating season.

The Company has adequate borrowing capacity to meet its financing requirements. Bank loans and commercial paper, supported by available credit, are used to meet short-term financing requirements. Interest rates on these short-term loans averaged 1.2% during 2003. During 2003, the Company maintained, with a group of banks, a three-year revolving credit agreement providing $250 million of available credit, and a 364-day credit agreement providing $250 million of available credit that expired in 2005 and 2003, respectively. On October 30, 2003, the Company replaced its existing credit agreements with a $500 million 364 day credit facility, which will automatically extend to a three year facility upon receipt of an approval of the PA PUC. The Company received the PA PUC approval in the January 2004. The 2003 credit agreement may be used for, among other things, credit support for the Company s commercial paper program. As of December 31, 2003, the Company has the authority to arrange for a commercial paper program up to $650 million. Commercial paper of $199.6 million is outstanding at December 31, 2003.

The Company s credit ratings, as determined by either Standards & 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 credit rating, the higher the level of fees and borrowing rate. As of December 31, 2003, the Company had not borrowed any amounts against these lines of credit. Facility fees, averaging one-eleventh of one percent in both 2003 and 2002, were paid to maintain credit availability.

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.

Financing Triggers

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, sell assets, and 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.

Risk Management

The Company s overall objective in its hedging program is to protect earnings from undue exposure to the risk of falling commodity prices. The Company hedges natural gas through financial instruments including forward contracts, swap 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, options and other contractual agreements.

Equitable has taken advantage of favorable gas prices to significantly hedge production. As of December 31, 2003, the approximate volumes and prices of Equitable s hedges and fixed-price contracts for 2004 2006 are:

	2004	2005	2006
Volume (Bcf)	50	47	45
Average Price (NYMEX)*	4.56	4.65	4.43

* The above price is based on a conversion rate of 1.05 MMbtu/Mcf. The average conversion rate associated with the Company s total reported sales volumes for 2003 is 1.11 MMbtu/Mcf before processing.

With respect to hedging as of December 31, 2003, the Company s exposure to changes in natural gas commodity prices under current market conditions is $0.01 per diluted share per $0.10 change in the average NYMEX natural gas price for 2004 and $0.02 to $0.03 per diluted share for 2005 and 2006. Additionally, the Company has hedges through 2010. In addition to monetizations, the Company uses derivative instruments to hedge its exposure. The Company has relied almost exclusively on fixed price swaps to accomplish the remainder of this objective during 2001, 2002 and 2003 due to the increased market volatility.

Investment Securities

As more fully described under Equity in Nonconsolidated Investments, as a result of the decreased ownership percentage in Westport, in the first quarter 2003 the Company changed the accounting treatment for its investment in Westport from the equity method to available-for-sale. Investments classified by the Company as available-for-sale consist of debt and equity securities, including the investment in Westport as of December 31, 2003. In accordance with Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities (Statement No. 115), available-for-sale securities are required to be carried at fair value, with any unrealized gains and losses reported on the Consolidated Balance Sheet within a separate equity component, accumulated other comprehensive income. The Statement also requires the Company to perform an impairment analysis to assess whether a decline in fair market value below the amortized cost is other-than-temporary. If the decline is deemed to be other-than-temporary, the securities must be written down to fair value, as the new cost basis, and the amount of the impairment must be included in earnings.

At December 31, 2003, the Company s investment in Westport is in an unrealized gain position. The Company s gross unrealized losses relating to its other securities were approximately $0.2 million. The Company performed an impairment analysis in accordance with Statement No. 115 and concluded that the decline below cost is temporary.

Equity in Nonconsolidated Investments

Westport

The Company owns approximately 11.53 million shares, or 17.1% of Westport, which decreased from 20.8% at the end of 2002. The Company does not have operational control of Westport. The decrease in the Company s ownership in Westport is a result of the Company s donation of 905,000 shares of Westport stock to a community giving foundation on March 31, 2003, the sale of approximately 1,260,000 shares on November 24, 2003 and the sale of 220,000 shares on December 22, 2003. The proceeds from these sales were used to fund contributions to the Company s defined benefit pension plan. The foundation was established by the Company and is projected to facilitate the Company s charitable giving program for approximately 10 years. The contribution resulted in charitable contribution expense of $9.3 million with a corresponding tax benefit of approximately $7.1 million (see Note 6 to the consolidated financial statements).

As a result of the decreased ownership, the Company changed the accounting treatment for its investment in the first quarter of 2003 from the equity method to available-for-sale, effective March 31, 2003. The change in accounting method eliminated the inclusion of Westport s results subsequent to March 31, 2003 in the Company s earnings. Also, the Company s investment in Westport was reclassified to Investments, available-for-sale as of March 31, 2003, and was adjusted to fair market value, in accordance with Statement No. 115. The equity investment at the time it was reclassified totaled $134.1 million. As of June 30, 2003, the Company recorded a reclassification adjustment of $52.9 million to reduce accumulated other comprehensive income and increase common stock to reflect the increases in the book basis of the Company s investment in Westport from previous Westport capital transactions. Therefore, the total mark-to-market basis of the Westport investment was unchanged as of June 30, 2003, but the increase in common stock value will prospectively reduce any realized gains on the sale of Westport stock by the Company due to the increase in book basis to $16.53 per share, from $10.25 per share.

The fair market value of the Company s investment in Westport was $344.2 million as of December 31, 2003 and was calculated based upon the quoted market price of Westport stock on that date. If the Company were to immediately liquidate its investment position in Westport, it would likely be at some discount to the quoted market price. The adjusted cost basis of the investment as of December 31, 2003 is $190.6 million. The increase in the carrying value of the investment of $153.7 million represents an unrealized gain on the investment which has been recorded in accumulated other comprehensive income net of applicable tax adjustments.

Equitable has announced its desire to sell additional shares so that the aggregate number of shares of Westport common stock sold in the six months subsequent to October 2003 equals approximately 3,000,000. The additional sales may occur through an underwritten offering, a registered, negotiated transaction, additional Rule 144 transactions or as otherwise permitted under the Registration Rights Agreement. Equitable is engaged in discussions with Westport regarding appropriate means of effecting these additional sales. The foregoing is subject to the terms of a Registration Rights Agreement with Westport. This Form 10-K does not constitute an offer of any securities for sale. The sale of any Westport common stock will be made only by means of a prospectus or pursuant to an exemption from registration.

NORESCO

In the second quarter 2003, the Company reevaluated its interest in Hunterdon and concluded that the Company effectively controls this equity investment for consolidation purposes. Further, the Company is the primary beneficiary of Plymouth under the rules of FIN No. 46. As a result, the Company began consolidating the financial positions, results of operations and cash flows of Hunterdon effective June 30, 2003 and Plymouth effective July 1, 2003. Hunterdon and Plymouth are considered to be part of the NORESCO segment.

The consolidation of Hunterdon removed the equity investment in Hunterdon of $2.5 million and increased minority interest by $2.5 million. As of December 31, 2003, Hunterdon had $7.3 million of total assets, and $3.0 million of total liabilities, including $2.4 million of nonrecourse long-term debt of which $0.5 million was classified as current. The consolidation of Plymouth removed the equity investment in Plymouth of $0.1 million and increased minority interest by $0.7 million. As of December 31, 2003, Plymouth had $4.7 million of total assets, and $4.1 million of total liabilities, including $4.0 million of nonrecourse long-term debt of which $0.2 million was classified as current.

The Company owned a 50% interest in Capital Center Energy Company, LLC (Capital Center), the supplier of power and conditioned air to a mall located in Providence, RI. On October 31, 2003, the Company sold its interest in the Capital Center to the mall owner. The Company recorded an immaterial gain on the sale.

Certain NORESCO projects are held through equity in nonconsolidated entities that consist of private power generation, cogeneration and central plant facilities located in selected international locations. When possible, long-term power purchase agreements (PPAs) are signed with the customer whereby the customer agrees to purchase the energy generated by the plant. The length of these contracts ranges from 1 to 7 years. The Company has not made an investment since April 2001 and has a total cumulative investment in these projects of $27.3 million as of December 31, 2003. The Company s share of the earnings for 2003, 2002 and 2001 related to the total investment was $2.5 million, $4.7 million and $7.6 million, respectively. These projects generally are financed on a project basis with nonrecourse financings established at the project level.

One of the Company s two Panamanian projects, in which the Company owns a 45% interest, Petroelectrica de Panama LDC (Petroelectrica), was a party to a five-year PPA, which expired in February 2003. The project debt was fully satisfied in December 2002. In the fourth quarter of 2003, Petroelectrica was unable to secure a PPA for the year 2004 and the plant was shut down in January 2004. The owners are analyzing several strategic alternatives for the project, which include a permanent or temporary shut down of the plant or a sale of the plant. The Company performed an impairment analysis of its equity interest in this project as of December 31, 2003. The result was that an impairment of $11.1 million was recorded and represents the full value of NORESCO s equity investment in the project.

The Company owns a 50% interest in another Panamanian electric generation project, IGC/ERI Pan-Am Thermal Generating Limited (IGC/ERI). The loan agreement required the project company to retrofit the plant to conform to Panamanian environmental noise standards by a target date of August 31, 2001. Unforeseen events delayed the final completion date of the required retrofits, and the project obtained an extension from the Panamanian government while the government evaluated a land acquisition/rezoning proposal, which, if accepted and executed, would eliminate the need for a retrofit requirement. In September and October 2002, the Panamanian government adopted two resolutions that affected the plant s compliance requirements by suspending the noise mitigation deadline while the Company achieved the objectives of the land acquisition and rezoning proposal, and by modifying the noise standards applicable to the plant by making them less stringent. In June 2003, the Supreme Court of Panama found unconstitutional the compliance requirement that modified the noise standards applicable to the plant. A Health Ministry decree applying the less restrictive noise standard in a manner the Company believes does not violate the June 2003 Supreme Court capitalized ruling was issued in January 2004. In October 2003, the creditor sponsor advised the project company that if the less restrictive noise standards are made applicable to the plant, the project company should execute portions of the land acquisition/rezoning proposal and work with a noise control contractor to achieve a partial technical resolution to the noise condition. If the plant is made compliant with the less restrictive noise standard, the creditor sponsor has indicated that it will issue a waiver from the loan agreement requirement and/or deem the borrower to be in compliance. In view of the January 2004 decree, the project company expects to execute the land acquisition/rezoning plan in consultation with the creditor sponsor. The expected cost to the project company of achieving resolution of this issue is not expected to exceed $1.5 million and would be funded by project funds.

Additionally, IGC/ERI experienced poor financial performance during 2002 due to adverse weather (abnormally high rainfall), other adverse market-related conditions, and reduced plant availability related to planned and unplanned outages. These factors depressed revenues, causing a drop below the minimum debt service coverage ratio covenant of the non-recourse loan document. The project company has been actively coordinating with the creditor sponsor on this matter and during the second half of 2002 and year ended 2003, experienced improvement in operational and financial performance. Despite the debt service coverage ratio issues, 2004 cash flows are expected to cover operating expenses and debt service requirements for IGC/ERI. The Company performed an impairment analysis of its equity interest in this project as of December 31, 2003. No impairment was required.   IGC/ERI will compete to sign new long-term power purchase agreements with customers in the second and third quarters of 2004. The outcome of these contracts could impact the value of the Company s investment. The Company will reassess the impairment analysis late in 2004. The value of the Company s investment in IGC/ERI is $21.7 million at December 31, 2003.

Finally, in 2003, IGC/ERI inadvertently violated a covenant in the project loan agreement, which restricts contracting for certain power sales. The violation was disclosed to the creditor sponsor. The power sales contract that created the violation expired December 31, 2003.

Supply

During 2000, Equitable Supply sold an interest in oil and gas properties to a partnership, ESP. The Company retained a 1% interest and negotiated arms-length, market-based rates for gathering, marketing and operating fees with the partnership in order to deliver its natural gas to the market. The Company treats ESP partnership interests as equity in nonconsolidated investments.

Also in 2000, Equitable Supply sold an interest in oil and gas properties to a trust, ANGT. The Company retained a 1% interest and has separately negotiated arms-length, market-based rates with ANGT for gathering, marketing, and operating fees to deliver its natural gas to the market. Additionally, the Company provides a liquidity reserve guarantee to Appalachian NPI (ANPI), secured by the fair market value of the assets purchased by ANGT. This guarantee is subject to certain restrictions and limitations, as defined in the guarantee agreement, as to the eligibility, amount and terms of the guarantee. These restrictions 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. The Company treats its interest in ANGT as equity in nonconsolidated investments.

Prepaid Natural Gas Sales

In December 2000, the Company entered into two prepaid natural gas sales contracts for a total of approximately 52.7 Bcf of reserves. The Company is required to deliver certain fixed quantities of natural gas during the term of the contracts. The first contract was for five years with net proceeds of $104.0 million and has two years remaining. The second contract was for three years with net proceeds of $104.8 million and was completed at the end of 2003. These contracts were recorded as prepaid forward sales and are recognized in income as deliveries occur.

Acquisitions and Dispositions

In December 2001, the Company sold its oil-dominated fields in order to focus on natural gas activities. The sale resulted in a decrease of 63 Bcfe of proved developed producing reserves and 5 Bcfe of proved undeveloped reserves for proceeds of approximately $60 million. The field produced approximately 4 Bcfe annually. Although the Company no longer operates these properties, it continues to gather and market the natural gas produced for a fee. During 2003 and 2002, these fees were approximately $1.7 million and $1.5 million, respectively.

In February 2003, the Company purchased the remaining 31% limited partnership interest in ABP from the minority interest holders for $44.2 million. The 31% limited partnership interest represents approximately 60.2 Bcf of reserves. As a result, effective February 1, 2003, the Company no longer recognizes minority interest expense associated with ABP, which totaled $0.9 million and $7.1 million for the years ended December 31, 2003 and 2002, respectively.

In February 2003, the Company sold approximately 500 of its low-producing wells, within two of its non-strategic districts, in two separate transactions. The sales resulted in a decrease of 13.0 Bcf of net reserves for proceeds of approximately $6.6 million. The wells produced an aggregate of approximately 1.0 Bcf in 2002. The Company did not recognize a gain or a loss as a result of this disposition.

Newly Adopted Accounting Standards

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations (Statement No. 143). Statement No. 143 was adopted by the Company effective January 1, 2003, and its primary impact was to change the method of accruing for well plugging and abandonment costs. These costs were formerly recognized as a component of depreciation, depletion and amortization (DD&A) expense with a corresponding credit to accumulated depletion in accordance with SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies (Statement No. 19). At the end of 2002, the cumulative credit included within accumulated depletion totaled approximately $20.9 million. Statement 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 will increase 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 DD&A, and the initial capitalized costs are depleted over the useful lives of the related assets.

The adoption of Statement No. 143 by the Company resulted in an after-tax charge to earnings of $3.6 million, or $0.06 per diluted share, which is reflected as a cumulative effect of accounting change in the Company s Statement of Consolidated Income for the year ended December 31, 2003. In addition to the charge to earnings, the depletion rate in the Company s Supply segment increased by $0.03 per Mcfe. The Company also recognized a $28.7 million other long-term liability and a $2.3 million long-term asset upon adoption of Statement No. 143. The long-term obligation represents the net present value of the estimated future expenditures required to plug and abandon the Company s approximately 12,000 wells in Appalachia, significant portions of which are not projected to occur for over 40 years.

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, 2003 (Thousands)
Asset retirement obligation as of beginning of period	$	28,690
Accretion expense		1,948
Liabilities incurred		431
Liabilities settled		(1,289)
Asset retirement obligation as of end of period	$	29,780

Assuming retroactive application of the change in accounting principle as of January 1, 2002, the pro forma effect of applying this new accounting principle on a retroactive basis would not materially change reported net income for the year ended December 31, 2002. Long-term liabilities, assuming retroactive application of the change in accounting principle as of January 1, 2002 and December 31, 2002, would have increased by $26.9 million and $28.7 million, respectively.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities (Statement No. 146), which supercedes EITF No. 94-3, Liability Recognition for Certain Employment

Termination Benefits and Other Costs to Exit an Activity. Statement No. 146 requires companies to record liabilities for costs associated with exit or disposal activities to be recognized only when the liability is incurred instead of at the date of commitment to an exit or disposal activity. Adoption of this statement was effective for exit or disposal activities that were initiated after December 31, 2002. The adoption of this statement did not have a material impact on the Company s financial position, results of operations or cash flows.

In November 2002, the FASB issued Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (FIN No. 45). FIN No. 45 clarifies and expands on existing disclosure requirements for guarantees, including loan guarantees. It also requires that, at the inception of a guarantee, the Company recognize a liability for the fair values of its obligation under that guarantee. The initial fair value recognition and measurement provisions are applied on a prospective basis to certain guarantees issued or modified after December 31, 2002. The disclosure provisions are effective for financial statements of periods ending after December 15, 2002. The adoption of FIN No. 45 did not have a material impact on the Company s financial position, results of operations or cash flows.

In November 2002, the EITF reached a consensus on Issue No. 00-21, Revenue Arrangements with Multiple Deliverables (EITF No. 00-21). EITF No. 00-21 provides guidance on how to account for arrangements that involve the delivery or performance of multiple products, services and rights to use assets. The provisions of EITF 00-21 apply to revenue arrangements entered into in the fiscal periods beginning after June 15, 2003. The adoption of EITF No. 00-21 did not have a material impact on the Company s financial position, results of operation or cash flows.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN No. 46). FIN No. 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Prior to FIN No. 46, entities were generally consolidated by an enterprise when the enterprise had a controlling financial interest through ownership of a majority voting interest in the entity. FIN No. 46 is effective for all new variable interest entities created or acquired after January 31, 2003. The Company adopted FIN No. 46 for variable interest entities created or acquired prior to February 1, 2003 as of July 1, 2003. The adoption of FIN No. 46 required the consolidation of Plymouth Cogeneration Limited Partnership (Plymouth), a joint venture entered into by NORESCO, and the deconsolidation of EAL/ERI Cogeneration Partners LP (Jamaica), which is the partnership that holds the Jamaican power plant.

During 1992, NORESCO entered into the Plymouth joint venture to construct, own and operate a cogeneration facility and provide electricity and steam to Plymouth State College. NORESCO originally recorded its interest in Plymouth on the Company s consolidated financial statements as equity in nonconsolidated investments. Under FIN No. 46, NORESCO is the primary beneficiary of Plymouth and began consolidating Plymouth in the consolidated financial statements effective July 1, 2003. The equity interests in Plymouth not owned by NORESCO are reported as a minority interest in the accompanying consolidated financial statements.

The consolidation of Plymouth removes the equity investment in Plymouth of $0.1 million and increases minority interest by $0.7 million in the Company s consolidated financial statements. As of December 31, 2003, the Company consolidated $4.7 million in assets and $4.1 million in total liabilities, including nonrecourse long-term debt of $4.0 million of which $0.2 million was classified as current.

NORESCO has a 91.2% interest in Jamaica and has historically consolidated Jamaica in the Company s financial statements. In the second quarter of 2002, the Company wrote off its entire investment in Jamaica due to poor performance. In the second quarter of 2003, ERI JAM, LLC, the entity that holds the Company s interest in Jamaica declared bankruptcy and Jamaica stopped operations.

Upon adoption of FIN No. 46, it was determined that Jamaica was a variable interest entity and that the Company was not the primary beneficiary. As a result, the Company deconsolidated Jamaica effective July 1, 2003. The deconsolidation of Jamaica removes from the Consolidated Balance Sheet $17.8 million of assets and $18.0 million of total liabilities, including nonrecourse project financing of $15.9 million, all of which was current. The Company did not establish an equity method investment in Jamaica upon deconsolidation, as the amount of such investment would be less than zero and there is no recourse against the Company beyond its investment in Jamaica.

The Company also has an interest in a variable interest entity, ANPI, in which Equitable was not deemed to be the primary beneficiary. As of December 31, 2003, ANPI had approximately $266.4 million of total assets and approximately $274.2 million of total liabilities (including $191.7 million of long-term debt, including current maturities), excluding minority interest. The Company s maximum exposure to a loss as a result of its involvement with ANPI is estimated to be $29.0 million.

In December 2003, the FASB issued a revision to FIN No. 46 (FIN No. 46R) clarifying some of the provisions of the interpretation and to exempt certain entities from its requirements. The Company is required to adopt the provisions of FIN No. 46R for interim periods ending after March 15, 2004. The Company is currently evaluating the impact that the adoption of this revision could have on its financial position and results of operations.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (Statement No. 149). This Statement amends and clarifies the accounting and reporting for derivative instruments, including embedded derivatives, and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (Statement No. 133). Statement No. 149 amends Statement No. 133 to reflect the decisions made as part of the Derivatives Implementation Group (DIG) and in other FASB projects or deliberations. Statement No. 149 is effective for contracts entered into or modified after September 30, 2003, and for hedging relationships designated after September 30, 2003. The Company s accounting for derivative instruments is in compliance with Statement No. 149 and Statement No. 133. Therefore, the adoption of Statement No. 149 did not have a material impact on the Company s financial position, results of operations or cash flows.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity (Statement No. 150). This Statement requires that certain financial instruments embodying an obligation to transfer assets or to issue equity securities be classified as liabilities. It is effective for financial instruments entered into or modified after May 31, 2003 and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. The adoption of Statement No. 150 did not have a material impact on the Company s consolidated financial position, results of operations or cash flows.

In December 2003, the FASB issued SFAS No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits (Statement No. 132). This Statement revises employers disclosures about pension plans and other postretirement benefits. It retains the original disclosure requirements contained in SFAS No. 132, Employers Disclosures about Pensions and Other Postretirement Benefits, and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. This Statement is effective for financial statements with fiscal years ending after December 15, 2003. Accordingly, the additional disclosures required by the revised Statement No. 132 have been included in Note 17 to the consolidated financial statements. Interim period disclosures required by revised Statement No. 132 are effective for interim periods beginning after December 15, 2003.

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. In January 2004, the FASB issued Staff Position 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (FSP FAS 106-1). This position permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Act. As permitted by FSP FAS 106-1, the Company has elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. In accordance with FSP FAS 106-1, appropriate disclosures related to the deferral election have been made in Note 17 to the consolidated financial statements

The American Institute of Certified Public Accountants has issued an exposure draft Statement of Position (SOP), Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment (PP&E). This proposed SOP applies to all nongovernmental entities that acquire, construct or replace tangible property, plant and equipment including lessors and lessees. A significant element of the SOP requires that entities use component accounting retroactively for all PP&E assets to the extent future component replacement will be capitalized. At adoption, entities would have the option to apply component accounting retroactively for all PP&E assets, to the extent applicable, or to apply component accounting as an entity incurs capitalizable costs that replace all or a portion of PP&E. The SOP is expected to be presented for FASB clearance in the first quarter of 2004 and would be applicable for fiscal years beginning after December 15, 2004. The Company is currently evaluating the impact that the adoption of this SOP would have on its financial position and results of operations.

Non-GAAP Disclosures

The SEC issued a final rule regarding the use of non-Generally Accepted Accounting Principals (GAAP) financial measures by public companies effective after March 2003. The rule defined a non-GAAP financial measure as a numerical measure of an issuer s historical or future financial performance, financial position or cash flows that:

1) Exclude amounts, or is subject to adjustments that have the effect of excluding amounts, that are included in the comparable measure calculated and presented in accordance with GAAP in the financial statements.

2) Includes amounts, or is subject to adjustments that have the effect of including amounts, that are excluded from the comparable measure so calculated and presented.

The Company has reported operating income, equity in earnings of nonconsolidated investments, excluding Westport, and minority interest by segment and by operations within each segment in the MD&A section of this Form 10-K. Interest charges 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.

The Company has reconciled the segments operating income, equity in earnings of nonconsolidated investments, excluding Westport, and minority interest to the Company s consolidated operating income, equity earnings from nonconsolidated investment, excluding Westport, and minority interest 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 MD&A section of this Form 10-K, and where appropriate, has provided information describing how a measure was derived. Equitable s management believes that presentation of this non-GAAP information provides useful information to management and investors regarding 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 of interest and income taxes. In addition, management uses these measures for budget planning purposes.

Off-Balance Sheet Arrangements

The Company has issued in favor of ANPI a liquidity reserve guarantee, which is subject to certain restrictions and limitations, and is secured by the fair market value of the assets purchased by ANGT. The Company received a market based fee for the issuance of the reserve guarantee. As of December 31, 2003, the maximum potential amount of future payments the Company could be required to make under the liquidity reserve guarantee is estimated to be $29.0 million. As of December 31, 2003, the Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN No. 45 and has not been modified subsequent to issuance.

The Company has certain minority investments representing ownership interests in transactions by which natural gas producing properties located in the Appalachian Basin region of the United States were sold. The Company has entered into agreements with these entities to provide gathering, and operating services to deliver their 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 total revenue earned from these fees totaled approximately $23.7 million for the year ended December 31, 2003.

The Company has equity investments in certain independent power plant projects located domestically as well as in select other countries. These investments are financed with nonrecourse debt. The Company has entered into agreements with these entities to provide administrative and development services. The total revenue earned from these fees totaled approximately $0.7 million for the year ended December 31, 2003. This amount includes six months of Hunterdon and Plymouth.

A wholly owned subsidiary of the Company has provided two guarantees in the aggregate amount of $5.4 million in support of a 50% owned non-recourse financed energy project in Panama. The guarantees represent 50% of the performance guaranty for the project s principal power purchase agreement and cover a project loan debt service reserve requirement. In accordance with FIN No. 45, the Company has not recorded a liability for this guarantee.

In order to accelerate cash collections, Equitable executes transactions to sell certain contract receivables to a financial institution and a variable interest entity. The variable interest entity is a multi-seller conduit that purchases contract receivables from several energy companies. The Company has no ownership interest in or control of the variable interest entity. As further described in Note 1 to the consolidated financial statements, the Company does not retain any interest in the contract receivables once the sale is complete. For the year ended December 31, 2003, approximately $27.6 million of the contract receivables met the criteria for sales treatment.

Pension Plans

Poor equity market conditions that existed from 2000 to 2002 contributed to a significant reduction in the fair market value of the Company s pension plan assets. As a result, the Company s benefit obligation relating to its pension plans became significantly under funded. The Company made cash contributions totaling $49.6 million to its pension plan during the first three quarters of 2003. In accordance with current funding guidelines, these contributions were designated as 2002 plan year contributions and, in the aggregate, represent the maximum allowable contribution that the Company could make to its pension plan for that plan year. In the fourth quarter of 2003, the Company made an additional cash contribution totaling $2.2 million to its pension plan. In accordance with current funding guidelines, this contribution was designated as a 2003 plan year contribution. As a result of the cash contributions, the Company s minimum funding requirement is zero for the 2003 plan year and based upon current assumptions, is expected to continue to be zero through the 2006 plan year. The Company was not required to, and consequently did not make any contribution to its pension plans during the years ended December 31, 2002 and 2001.

The reduction in the fair market value of the Company s pension plan assets over the last three years, coupled with decreases in the expected rate of return on pension plan assets and increases in the amount of unrecognized actuarial losses, has also contributed to increases in the amount of pension expense recognized by the Company. Total pension expense recognized by the Company in 2003, 2002, and 2001, excluding special termination benefits and curtailment losses, totaled $5.1 million, $5.3 million, and $3.8 million, respectively. In the fourth quarter of 2003, the Company froze the pension benefit provided through a defined benefit plan to approximately 340 salaried employees. The Company now provides benefits to these employees under a defined contribution plan that covers all other salaried employees of the Company. The decrease in service cost related to the conversion of this benefit plan, coupled with the cash contributions made by the Company in 2003, will decrease the expected amount of pension expense to be recognized by the Company in future years. Total pension expense expected to be recognized by the Company in 2004, exclusive of any special termination benefits and curtailment losses, is $2.3 million. This decrease in pension expense will be partially offset by increased defined contribution plan expense in 2004.

Restricted Stock

The Company continues to shift its compensation focus from the issuance of stock options to employees towards performance-based stock units and time-restricted stock awards. Stock options awarded in 2003 decreased significantly compared to those awarded in 2002. Additionally, the Compensation Committee of the Company s Board of Directors has indicated a desire to fully replace stock options with restricted stock in 2004.

Energy Bill

As a result of the Company s increased partnership interest in ABP in 2002, the Company began receiving a greater percentage of the nonconventional fuels tax credit attributable to ABP. This resulted in a reduction of the Company s effective tax rate during 2002. The nonconventional fuels tax credit expired at the end of 2002, and it is currently unclear whether legislation will be enacted to allow this tax benefit to exist in the future. On November 18, 2003, the Energy Policy Act of 2003 (H.R. 6) was passed by the House of Representatives. This comprehensive energy policy legislation, as reported by conferees from the House of Representatives and the Senate, included an extension of the nonconventional fuels tax credit for existing qualifying wells and for newly drilled qualifying wells.

The Senate was unable to pass H.R. 6 before adjourning for the year due to a lack of votes needed to avoid a threatened filibuster. This comprehensive energy legislation is expected to be addressed by the Senate and House of Representatives during 2004, but any extension of the nonconventional fuels tax credit continues to remain uncertain.

On September 30, 2003, the enabling legislation for the performance contracting work that NORESCO performs for the federal government under the Department of Energy contracts lapsed and is pending extension in Congress. Until this issue is resolved, the NORESCO segment s ability to sign new contracts under the Department of Energy master agreements is affected. However, the Department of Defense has informed NORESCO that it is not interpreting the statutory lapse as prohibiting new awards under existing master agreements.

Rate Regulation

The Company s distribution operations are subject to comprehensive regulation by the PA PUC, the Public Service Commission of West Virginia, and 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, Accounting for the Effects of Certain Types of Regulation. As described in Notes 1 and 11 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 Certain Contractual Obligations

The following table details the future projected payments associated with the Company s significant contractual obligations as of December 31, 2003.

	Total	2004	2005-2006	2007-2008	2009+
			(Thousands)		
Interest expense	$ 548,999	$ 39,391	$ 76,506	$ 74,456	$ 358,646
Long-term debt	653,414	21,267	14,750	11,307	606,090
Operating leases	69,645	6,669	12,594	10,456	39,926
Purchase obligations	197,120	32,620	58,547	45,005	60,948
Total contractual cash obligations	$ 1,469,178	$ 99,947	$ 162,397	$ 141,224	$ 1,065,610

The indentures and other agreements governing the Company s long-term debt 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, 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.

Operating leases are primarily entered into for various office locations and warehouse buildings, as well as a limited amount of equipment. In the third quarter of 2003, the Company signed a long-term lease for office space with Continental Real Estate Companies, which will own and construct the building in which the office space will be located. Plans call for the building to be complete in late 2004 or early 2005. The office space is located at the North Shore in Pittsburgh, Pennsylvania and will allow Equitable to consolidate its Pittsburgh office operations and increase efficiencies. The term of the lease is 20 years and nine months and the base rent is approximately $2 million per year. Relocation of operations from locations that utilize space under long-term leases will likely cause additional expense late in 2004 and 2005. The base rent payments of approximately $2 million per year have been included in the table above with payments commencing in 2005.

Included within the purchase obligations amount in the table above are annual commitments of approximately $24.5 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 nine years at December 31, 2003. Approximately $19.5 million of these costs are recoverable in customer rates.

Contingent Liabilities and Commitments

There are various claims and legal proceedings against the Company arising in the normal course of business. Although counsel is unable to predict with certainty the ultimate outcome, management and counsel believe that the Company has significant and meritorious defenses to any claims and intends to pursue them vigorously. The Company has provided adequate reserves and therefore believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the financial position of the Company. The reserves recorded by the Company do not include any amounts for legal costs expected to be incurred. It is the Company s policy to recognize any legal costs associated with any claims and legal proceedings against the Company as they are incurred.

After an extended period of troubled operations, ERI JAM, LLC, a subsidiary that holds the Company s interest in EAL/ERI Cogeneration Partners LP, an international infrastructure project, filed for bankruptcy protection under Chapter 11 in U.S. Bankruptcy Court (Delaware) in April 2003. In the third quarter 2003, ERI JAM, LLC transferred control of the international infrastructure project under the partnership agreement to the other general partner. The international infrastructure project was deconsolidated in accordance with FIN No. 46. In September 2003, project-level counterparties, Jamaica Broilers Group Limited (JBG) and Energy Associated Limited (EAL), filed a claim against ERI JAM LLC as Debtor-in-Possession in the Chapter 11 case. EAL is a limited partner in EAL/ERI Cogeneration Partners LP. In October 2003, JBG and EAL also filed a multi-count complaint against Equitable and certain of its affiliates in U.S. District Court (Western District of PA). Equitable and its affiliates intend to vigorously defend this litigation, which they view as without merit. Resolution within the Chapter 11 proceedings pursuant to a global settlement is sought.

The various regulatory authorities that oversee Equitable s operations will, from time to time, make inquiries or investigations into the activities of the Company. The Company has received informal requests for information from the CFTC regarding the reporting of prices to industry publications during 2001, 2002 and 2003. The Company has cooperated fully with the CFTC in this matter as the Company always does when regulatory bodies make requests. The Company has investigated this matter thoroughly internally and uncovered no evidence to date that any of its employees ever intentionally reported any false information to any industry publication.

In July 2002, the United States EPA published a final rule that amends the Oil Pollution Prevention Regulation. The effective date of the rule was August 16, 2002. Under the final rule, Owners/Operators of existing facilities were to revise their SPCC plans on or before February 17, 2003 and were required to implement the amended plans as soon as possible but not later than August 18, 2003. On April 17, 2003, the EPA extended the deadline to adopt a plan amendment to August 17, 2004 and the deadline to comply with the amended plan to February 18, 2005. There is currently active litigation regarding the final rule and management anticipates that the regulation will be modified. Nonetheless the Company is studying, and is preparing to implement, its plan of compliance. The ultimate outcome of the pending litigation and any regulatory modification may affect the Company s ability to timely comply and will affect the total costs of compliance, currently expected to be $18.0 million, approximately two-thirds of which are expected to be capitalized but were not approved as part of the 2004 capital budget.

In addition to the SPCC requirement, the Company is subject to other 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.

Any estimated costs associated with identified situations that require remedial action are accrued with certain costs deferred as regulatory assets, as applicable. The Company has identified situations that require remedial action for which approximately $4.4 million is included in other long-term liabilities at December 31, 2003.

At the end of the useful life of a well the Company is required to remediate the site by plugging and abandoning the well. Costs associated with this obligation totaled $1.3 million, $0.7 million and $0.8 million during the years ended 2003, 2002, and 2001, respectively.

Inflation and the Effect of Changing Energy Prices

The rate of inflation in the United States has been less than moderate over the past several years and has not significantly affected the profitability of the Company. In prior periods of high general inflation, oil and natural gas prices generally increased at comparable rates; however, there is no assurance that this will be the case in the current environment or in possible future periods of high inflation. Regulated utility operations may be required to file a general rate case in order to recover higher costs of operations. Margins in the energy marketing business in the Equitable Utilities segment are highly sensitive to competitive pressures and may not reflect the effects of inflation. The results of operations in the Company s three business segments will be affected by future changes in oil and natural gas prices and the interrelationship between oil, natural gas and other energy prices. To help mitigate the effect of any future changes in natural gas prices, the Company has entered into hedging contracts with respect to forecasted natural gas production at specified prices for a specified period of time. The Company s hedging strategy and information regarding the derivative instruments used are outlined in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, and in Note 3 to the consolidated financial statements.

Audit Committee

The Audit Committee, composed entirely of independent directors, meets periodically with Equitable s independent auditors and management to review the Company s financial statements and the results of audit activities. The Audit Committee, in turn, reports to the Board of Directors on the results of its review and selects the independent auditors.

Transactions with Directors Affiliated Companies

In the course of ordinary business, the Company may have engaged in transactions with companies and organizations for which an Equitable Resources director serves as an officer. Those directors did not have a material interest in any such transactions and none of those transactions exceeded 5% of the gross revenues of either Equitable Resources or the other organization. Moreover, any such transactions were entered into on arms-length terms believed to be fair.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company s primary market risk exposure is the volatility of future prices for natural gas, which can affect the operating results of Equitable 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 Note 3 to the consolidated financial statements. The Company uses simple, nonleveraged derivative instruments that are placed with major institutions whose creditworthiness is continually monitored. 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.

For commodity price derivatives used to hedge forecasted Company production, Equitable sets policy limits relative to the expected production and sales levels, which are exposed to price risk. These financial instruments include forward contracts, swap 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, options and other contractual agreements. The level of price exposure is limited by the value at risk limits allowed by this policy. Management monitors price and production levels on a continuous basis and will make adjustments to quantities hedged as warranted. In general, Equitable s strategy is to become more highly hedged for production over the next several years at prices considered to be at the upper end of historical levels. The Company believes that prices between $3.00 and $3.50 per Mcf are sustainable. Above this range, non-traditional supplies become economically feasible. Furthermore, the Company expects price volatility to result in prices significantly higher and lower than this range. The Company attempts to take advantage of these price fluctuations by hedging more aggressively when prices are much higher than the range and by taking more price risk when prices are significantly below the range. However, the Company has typically not hedged material volumes unless the natural gas prices exceed $4.00 per Mcf. 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.

For commodity price derivatives held for trading positions, the marketing group will engage in financial transactions also subject to policies that limit the net positions to specific value at risk limits. These financial instruments include forward contracts, swap 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, options and other contractual agreements.

With respect to the energy derivatives held by the Company for purposes other than trading as of December 31, 2003, the Company continued to execute its hedging strategy by utilizing price swaps of approximately 219.4 Bcf of natural gas. These derivatives have hedged varying levels of expected equity production through 2010. A decrease of 10% in the market price of natural gas from the December 31, 2003 levels would increase the fair value of the natural gas instruments by approximately $108.4 million. An increase of 10% in market price of natural gas would decrease the fair market value by the same amount. With respect to derivative contracts held by the Company for trading purposes as of December 31, 2003, a decrease of 10% in the market price of natural gas from the December 31, 2003 level would decrease the fair market value by approximately $0.05 million. An increase of 10% in market price of natural gas from the December 31, 2003 level would increase the fair market value the same amount. The Company determined the change in the fair value of the natural gas instruments using a method 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, 2003. The price change was then applied to the natural gas instruments recorded on the Company s balance sheet, resulting in the change in fair value.

The above analysis of the energy derivatives held by the Company for purposes other than trading does not include the unfavorable impact that the same hypothetical price movement would have on the Company and its subsidiaries physical sales of natural gas. The portfolio of energy derivatives held for risk management purposes approximates the notional quantity 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 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 hedged 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 as applicable, anticipated transactions occur as expected.

The disclosure with respect to the energy derivatives relies on the assumption that the contracts will exist parallel to the underlying physical transactions. If the underlying transactions or positions are liquidated prior to the maturity of the energy derivatives, a loss on the financial instruments may occur, or the derivative might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first.

The Company has variable rate short-term debt. As such, there is some limited 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 fluctuating interest rates.

The Company may enter into interest rate derivative instruments to mitigate exposure to future changes in interest rates, but as of December 31, 2003 the Company had no such instruments outstanding.

The Company is exposed to market risk associated with its holdings in Westport, which is accounted for as an investment, available for sale. The Company does not attempt to reduce this risk through the use of derivatives.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT AUDITORS

The Board of Directors and Stockholders

Equitable Resources, Inc.

We have audited the accompanying consolidated balance sheets of Equitable Resources, Inc. and Subsidiaries as of December 31, 2003 and 2002, 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, 2003. 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 generally accepted in the 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, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, in 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Asset Retirement Obligations and of Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51. In 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangibles.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
January 27, 2004

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME

YEARS ENDED DECEMBER 31,

	2003	2002	2001
	(Thousands except per share amounts)		
Operating revenues	$ 1,047,277	$ 1,069,068	$ 1,109,334
Cost of sales	428,706	506,363	541,726
Net operating revenues (see Note 1)	618,571	562,705	567,608
Operating expenses:			
Operation and maintenance	76,319	73,430	80,607
Production and exploration	35,687	27,111	34,500
Selling, general and administrative	126,210	109,825	124,743
Impairment of long-lived assets		5,320	
Depreciation, depletion and amortization	78,138	69,448	73,230
Total operating expenses (see Note 1)	316,354	285,134	313,080
Operating income	302,217	277,571	254,528
Charitable foundation contribution	(9,279)		
Gain on sale of available for sale securities	13,985		
Equity in (losses) earnings of nonconsolidated investments:			
Westport	3,614	(8,476)	17,820
Impairment in nonconsolidated investments	(11,059)		
Other	3,050	5,013	8,281
	(4,395)	(3,463)	26,101
Minority interest	(1,413)	(7,103)	
Interest expense	45,766	38,787	41,098
Income from continuing operations before income taxes and cumulative effect of accounting change	255,349	228,218	239,531
Income taxes	81,792	77,592	87,723
Income from continuing operations before cumulative effect of accounting change	173,557	150,626	151,808
Income from discontinued operations		9,000	
Cumulative effect of accounting change, net of tax	(3,556)	(5,519)	
Net income	$ 170,001	$ 154,107	$ 151,808
Earnings per share of common stock:			
Basic:			
Income from continuing operations before cumulative effect of accounting change	$ 2.80	$ 2.40	$ 2.36
Income from discontinued operations		0.14	
Cumulative effect of accounting change, net of tax	(0.06)	(0.09)	
Net Income	$ 2.74	$ 2.45	$ 2.36
Diluted:			
Income from continuing operations before cumulative effect of accounting change	$ 2.74	$ 2.36	$ 2.30

Income from discontinued operations		0.14	
Cumulative effect of accounting change, net of tax	(0.06)	(0.09)	
Net Income	$ 2.68	$ 2.41	$ 2.30

See notes to consolidated financial statements.

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

YEARS ENDED DECEMBER 31,

	2003	2002	2001
		(Thousands)	
Cash flows from operating activities:			
Income from continuing operations before cumulative effect of accounting change	$ 173,557	$ 150,626	$ 151,808
Adjustments to reconcile net income to net cash provided by operating activities:			
Provision for losses on accounts receivable	13,697	8,564	14,866
Depreciation, depletion and amortization	78,138	69,448	73,230
Impairment of assets		5,320	2,410
Impairment in nonconsolidated investments	11,059		
Charitable contribution	9,279		
Amortization of construction contract costs	1,680	3,581	1,811
Recognition of monetized production revenue	(55,705)	(55,705)	(84,453)
Deferred income taxes	69,084	42,869	62,340
Change in undistributed earnings from nonconsolidated investments	(6,664)	3,463	(22,248)
Minority interest	1,413	7,103	
Gain on sale of Westport stock	(13,985)		
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues	(28,588)	(89,860)	155,860
Inventory	(84,738)	21,710	(11,199)
Prepaid expenses and other	(1,416)	12,938	13,824
Regulatory assets	11,897	614	(17,470)
Accounts payable	9,741	34,824	(184,069)
Deferred income taxes	(4,800)	6,291	17,855
Pension contribution	(51,840)		
Other assets	(4,971)	(2,823)	(31,388)
Other liabilities	(5,808)	(4,452)	(13,308)
Total adjustments	(52,527)	63,885	(21,939)
Net cash provided by operating activities	121,030	214,511	129,869
Cash flows from investing activities:			
Capital expenditures	(221,499)	(218,494)	(132,679)
Purchase of minority interest in Appalachian Basin Partners, L.P.	(44,200)		
Investment in available-for-sale securities		(17,592)	
Contributions to nonconsolidated investments			(4,303)
Distributions from nonconsolidated investments	2,031	3,970	3,989
Proceeds from sale of Westport stock	38,419		
Proceeds from sale of equity in nonconsolidated investments	4,363		
Proceeds from sale of receivables			1,130
Proceeds from sale of property	6,550		69,058

Restricted cash from oil-dominated field sale				62,956		(62,956)
Net cash used in investing activities		(214,336)		(169,160)		(125,761)
Cash flows from financing activities:						
Dividends paid		(60,419)		(41,809)		(40,356)
Purchase of treasury stock		(55,235)		(97,028)		(61,203)
Proceeds from exercises under employee compensation plans		39,155		28,485		6,855
Loans against construction contracts		45,524		23,215		105,420
Proceeds from issuance of long-term debt		200,000		200,000		
Repayments and retirements of long-term debt		(24,733)		(641)		(10,405)
Redemption of Trust Preferred Capital Securities		(125,000)				
Increase (decrease) in short-term loans		93,600		(169,447)		(26,820)
Net cash provided by (used in) financing activities		112,892		(57,225)		(26,509)
Net increase (decrease) in cash and cash equivalents		19,586		(11,874)		(22,401)
Cash and cash equivalents at beginning of year		17,748		29,622		52,023
Cash and cash equivalents at end of year	$	37,334	$	17,748	$	29,622
Cash paid during the year for:						
Interest (net of amount capitalized)	$	47,212	$	40,154	$	40,258
Income taxes	$	4,661	$	18,941	$	15,396

See notes to consolidated financial statements.

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2003	2002
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 37,334	$ 17,748
Accounts receivable (less accumulated provision for doubtful accounts: 2003, $18,041; 2002, $15,294)	176,574	160,778
Unbilled revenues	129,758	130,348
Inventory	162,090	74,735
Derivative commodity instruments, at fair value	34,657	38,512
Prepaid expenses and other	9,648	7,930
Total current assets	550,061	430,051
Equity in nonconsolidated investments	89,175	245,792
Property, plant and equipment:		
Equitable Utilities	1,041,011	994,311
Equitable Supply	1,733,466	1,529,915
NORESCO	17,322	20,912
Total property, plant and equipment	2,791,799	2,545,138
Less: accumulated depreciation and depletion	1,025,017	983,323
Net property, plant and equipment	1,766,782	1,561,815
Investments, available-for-sale	363,280	16,098
Other assets:		
Regulatory assets	67,714	79,611
Goodwill	51,656	51,656
Long-term receivables	7,849	7,606
Other	43,375	44,262
Total other assets	170,594	183,135
Total	$ 2,939,892	$ 2,436,891

See notes to consolidated financial statements.

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2003	2002
	(Thousands)	
Liabilities and Common Stockholders Equity		
Current liabilities:		
Current portion of long-term debt	$ 21,267	$ 24,250
Current portion of nonrecourse project financing		16,055
Short-term loans	199,600	106,000
Accounts payable	146,086	136,478
Prepaid gas forward sale	20,840	55,705
Derivative commodity instruments, at fair value	137,636	46,768
Current portion of project financing obligations	56,368	73,032
Other current liabilities	121,030	93,452
Total current liabilities	702,827	551,740
Long-term debt:		
Debentures and medium-term notes	632,147	447,000
Total long-term debt	632,147	447,000
Deferred and other credits:		
Deferred income taxes	459,877	350,690
Deferred investment tax credits	12,125	13,210
Prepaid gas forward sale	20,783	41,591
Project financing obligations	48,972	13,684
Other credits	97,821	115,337
Total deferred and other credits	639,578	534,512
Preferred trust securities		125,000
Common stockholders equity:		
Common stock, no par value, authorized 160,000 shares; shares issued: 2003 and 2002, 74,504	348,133	287,597
Treasury stock, shares at cost: 2003, 12,137; 2002, 12,162; (net of shares and cost held in trust for deferred compensation of 636, $12,111 and 642, $12,273)	(295,145)	(271,930)
Retained earnings	897,087	787,505
Accumulated other comprehensive income (loss)	15,265	(24,533)
Total common stockholders equity	965,340	778,639
Total	$ 2,939,892	$ 2,436,891

See notes to consolidated financial statements.

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES

STATEMENTS OF COMMON STOCKHOLDERS EQUITY

YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

	Common Stock								
	Shares Outstanding		No Par Value		Retained Earnings		Accumulated Other Comprehensive Income (Loss)		Common Stockholders Equity
					(Thousands)				
Balance, December 31, 2000	65,078	$	129,933	$	563,755	$	7	$	693,695
Comprehensive income:									
Net income					151,808				151,808
Cumulative effect of SFAS No. 133 adoption, net of tax benefit of $21,077							(37,023)		(37,023)
Net change in natural gas cash flow hedges, net of tax expense of $75,098 (see Note 3)							139,468		139,468
Minimum pension liability adjustment, net of tax benefit of $5,962							(11,072)		(11,072)
Total comprehensive income									243,181
Dividends ($0.63 per share)					(40,356)				(40,356)
Stock-based compensation plans, net	576		10,837						10,837
Stock repurchases	(1,784)		(61,203)						(61,203)
Balance, December 31, 2001	63,870		79,567		675,207		91,380		846,154
Comprehensive income:									
Net income					154,107				154,107
Net change in cash flow hedges:									
Natural gas, net of tax benefit of $53,672 (see Note 3)							(99,678)		(99,678)
Interest rate							(1,150)		(1,150)
Unrealized loss on available-for-sale securities							(1,494)		(1,494)
Minimum pension liability adjustment, net of tax benefit of $6,744							(13,591)		(13,591)
Total comprehensive income									38,194
Dividends ($0.67 per share)					(41,809)				(41,809)
Stock-based compensation plans, net	1,378		33,128						33,128
Stock repurchases	(2,906)		(97,028)						(97,028)
Balance, December 31, 2002	62,342		15,667		787,505		(24,533)		778,639
Comprehensive income:									
Net income					170,001				170,001
Net change in cash flow hedges:									

Natural gas, net of tax benefit of $38,674 (see Note 3)				(61,140)	(61,140)
Interest rate				(133)	(133)
Unrealized gain on available-for-sale securities:					
Westport Resources (a)				99,630	99,630
Other				2,310	2,310
Minimum pension liability adjustment, net of tax benefit of $448				(869)	(869)
Total comprehensive income					209,799
Westport Resources cost basis adjustment (a)		52,857			52,857
Dividends ($0.97 per share)			(60,419)		(60,419)
Stock-based compensation plans, net	1,456	39,699			39,699
Stock repurchases	(1,432)	(55,235)			(55,235)
Balance, December 31, 2003	62,366	$ 52,988	$ 897,087	$ 15,265	$ 965,340

Common shares authorized: 160,000,000 shares. Preferred shares authorized: 3,000,000 shares. There are no preferred shares issued or outstanding.

(a) Includes a reclassification of $52.9 million to common stock as discussed in Note 1. Except for those described in Note 3, there were no other reclassification adjustments for any other categories in 2003, 2002 and 2001.

See notes to consolidated financial statements.

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2003

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, in most instances, utilizes the equity method of accounting for companies where its ownership is less than or equal to 50% and significant influence exists. As more fully discussed below, the Company s ownership in Westport Resources Corporation (Westport) decreased to 17.1% in 2003 and the Company does not have significant influence over the operations of Westport. As a result, the Company changed the accounting treatment for its investment in Westport from the equity method to available-for-sale, effective March 31, 2003.

Use of Estimates: The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the 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 charges.

Inventories: The Company s inventory balance consists of natural gas stored underground and materials and supplies. The amount of natural gas stored underground that is not related to the Company s energy trading activities plus the amount of materials and supplies are recorded at the lower of average cost or market. The amount of natural gas stored underground that was purchased on or before October 25, 2002 and that relates to energy trading activities was recorded at fair value in accordance with the Financial Accounting Standards Board s (FASB) Emerging Issues Task Force (EITF) No. 98-10, Accounting for Contracts Involved in Energy and Risk Management Activities (EITF No. 98-10). Subsequent to October 25, 2002, the Company has recorded the purchase of the physical inventory associated with its energy trading activities at the lower of cost or market in accordance with EITF No. 02-3, Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10 and 00-17 (EITF No. 02-3), which rescinded the guidance contained in EITF No. 98-10.

Properties, Plant and Equipment: The Company s properties, plant and equipment consists of the following:

	December 31,			
	2003		2002	
	(Thousands)			
Utility plant	$	1,038,586	$	991,891
Accumulated depreciation and amortization		349,129		339,846
Net utility plant		689,457		652,045
Gas and oil producing properties, successful efforts method		1,303,655		1,140,129
Accumulated depletion		450,761		406,399
Net oil and gas producing properties		852,894		733,730
Other properties, at cost less accumulated depreciation		224,431		176,040
Net property, plant and equipment	$	1,766,782	$	1,561,815

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, 2003 and December 31, 2002 was approximately 4% of net Utility properties.

Oil and gas producing properties use the successful efforts method of accounting for production activities. The majority of this line item consists of gas producing properties which were depleted at a rate of $0.49/mcf and $0.40/mcf produced for the years ended December 31, 2003 and December 31, 2002, respectively.

The Company also had $224.4 million and $176.0 million of other property at December 31, 2003 and December 31, 2002 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).

Planned 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.

Oil & Gas Properties: The Company uses 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, Ohio and Pennsylvania. Costs of exploratory dry holes, geological and geophysical, delay rentals, and other property carrying costs are charged to expense.

The carrying value 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, Equitable estimates the expected future cash flows (on an undiscounted basis) from the Company s 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 undiscounted 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, 2003 and 2002, the Company did not recognize impairment charges on oil and gas properties.

Additionally, the costs of unproved oil and gas properties are periodically assessed on a field-by-field basis. 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 26.

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 Pennsylvania Public Utilities Commission (PA PUC) and the Public Service Commission of West Virginia. The Company also provides field line service (also referred to as farm tap service as the customer is served directly from a well or gathering pipeline) 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 Federal Energy Regulatory Commission (FERC). Accounting for the Company s regulated operations is performed in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. 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 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 cease 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 occurred.

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

	Years Ended December 31,		
	2003	2002	2001
		(Thousands)	
Distribution revenues	$ 396,203	$ 330,865	$ 390,765
Pipeline revenues	52,926	56,742	64,260
Total regulated revenue	449,129	387,607	455,025
Distribution purchased gas costs	231,017	174,772	236,141
Pipeline purchased gas costs		67	2,181
Total purchased gas costs	231,017	174,839	238,322
Distribution net revenue	165,186	156,093	154,624
Pipeline net revenue	52,926	56,675	62,079
Total regulated net revenue	218,112	212,768	216,703
Distribution operating expenses	102,093	96,072	102,451
Pipeline operating expenses	30,511	31,297	41,121
Total regulated operating expenses	$ 132,604	$ 127,369	$ 143,572

Derivative Commodity 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 Company s Audit Committee of the Board of Directors and is comprised of the chief executive officer, the chief financial officer and other officers and employees.

The Company s risk management program includes the use of exchange-traded natural gas futures contracts and options and over-the-counter (OTC) natural gas swap agreements and options (collectively, derivative contracts) to hedge exposures to fluctuations in natural gas prices and for trading purposes. The Company s risk management program also includes the use of 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, Accounting for Derivative Instruments and Hedging Activities, (Statement No. 133) as amended by SFAS No. 137, Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of Financial Accounting Standards Board Statement No. 133 (Statement No. 137), SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities (Statement No. 138), and by SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (Statement No. 149). 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. The measurement of fair value is based upon actively quoted market prices when available. In the absence of actively quoted market prices, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based upon valuation methodologies deemed appropriate by the Company s CRC.

The accounting for the changes in fair value of the Company s derivative instruments depends on the use of the derivative instruments. To the extent that a derivative instrument has been designated and qualifies as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of accumulated other comprehensive income (net of tax) and is 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 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 have been designated and qualify as cash flow hedges.

In June 2002, the FASB issued EITF No. 02-3, Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, and No. 00-17, Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10. In the fourth quarter 2002, the FASB revised its consensus contained in EITF No. 02-3. EITF No. 02-3, as revised, rescinds the guidance contained in EITF No. 98-10 and requires that only energy trading contracts that meet the definition of a derivative in Statement No. 133 be carried at fair value. Energy trading contracts that do not meet the definition of a derivative must be accounted for as an executory contract (i.e., on an accrual basis).

Additionally, EITF No. 02-3, as revised, states that it is no longer an acceptable industry practice to account for energy inventory held for trading purposes at fair value when fair value exceeds cost, unless explicitly provided by other authoritative literature. The EITF s revised consensus is effective for all new energy trading contracts entered into and energy inventory held for trading purposes purchased after October 25, 2002. For any energy trading contracts entered into or energy inventory held for trading purposes as of October 25, 2002, companies were required to recognize a cumulative effect of a change in accounting principle beginning the first day of the first fiscal period beginning after December 15, 2002. The implementation of the above provisions of EITF No. 02-3, as revised, did not have a material impact on the Company s consolidated financial statements.

EITF No. 02-3, as revised, also requires that all gains and losses on derivative instruments held for trading purposes be presented on a net basis in the income statement for all periods presented, whether or not settled physically. For gains and losses on energy trading activities that are not derivatives pursuant to Statement No. 133, the presentation is determined based upon the guidance contained in EITF No. 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent. This guidance is effective for all periods presented in financial statements issued for periods beginning after December 15, 2002 (earlier adoption was permitted). Prior to this guidance, the Company reported the gains and losses on its energy trading contracts gross (i.e., included the revenues and costs comprising the gains and losses on energy trading derivative contracts within operating revenues and cost of sales, respectively) on its Statements of Consolidated Income in accordance with the guidance contained in EITF No. 98-10. The change from a gross to a net classification has resulted in a reduction in both operating revenues and cost of sales for the Equitable Utilities segment for the years ended December 31, 2002 and 2001 of $169.4 million and $592.0 million, respectively.

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 2003, 2002 and 2001 of $0.8 million, $1.4 million and $2.0 million, respectively, were capitalized as a portion of the cost of the related long-term assets.

Goodwill: Goodwill is the excess of the acquisition cost of businesses over the fair value of the identifiable net assets (tangible and intangible) acquired. Goodwill was required to be evaluated for impairment at the beginning of 2002 and on an annual basis going forward according to SFAS No. 142, Goodwill and Other Intangible Assets (Statement No. 142). The Statement requires that a two-step process be performed to analyze whether or not goodwill has been impaired. Step one requires that the fair value be compared to book value. If the fair value is higher than the book value, no impairment is indicated and there is no need to perform the second step of the process. If the fair value is lower than the book value, step two must be evaluated. Step two requires that a hypothetical purchase price allocation analysis be done to reflect a current book value of goodwill. This current value is then compared to the carrying value of goodwill. If the current fair value is lower than the carrying value, an impairment must be recorded. Annually, the goodwill is tested for impairment in the fourth quarter.

Impairment of Long-Lived Assets: In accordance with Statement 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.

During the second quarter 2002, the Company reviewed the Jamaica power plant project related to the NORESCO operating segment for impairment as the project had not been operating to expected levels in order to meet anticipated profit goals and remediation efforts were unsuccessful. The Company owns 91.2% of the equity in the project and therefore had consolidated the project in its financial statements until the adoption of FASB Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN No. 46) effective July 1, 2003. As a result of the Company s review, an impairment loss of $5.3 million was recorded to adjust the project assets to their fair value. Fair value was based on the expected future cash flows to be generated by the Jamaican power plant, discounted at the risk-free rate of interest.

Stock-Based Compensation: The Company accounts for its stock options and awards under the intrinsic-value-based method as defined in Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25). Accordingly, no compensation cost for fixed stock options is included in net income since all awards were made at the fair value on the date of grant. Compensation expense for restricted share awards is ratably recognized over the vesting period, based on the fair value of the stock on the date of grant. The Company applies the disclosure provisions of SFAS No. 123, Accounting for Stock-Based Compensation (Statement No. 123) and SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure an amendment of FASB Statement No. 123 (Statement No. 148).

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement No. 123 to employee stock-based awards. Refer to Note 20 for more information regarding stock based compensation.

	Year Ended December 31		
	2003	2002	2001
		(Thousands)	
Net Income, as reported	$ 170,001	$ 154,107	$ 151,808
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	11,879	5,975	1,384
Deduct: Total stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	18,015	12,910	8,084
Pro Forma net income	$ 163,865	$ 147,172	$ 145,108
Earnings per share:			
Basic, as reported	$ 2.74	$ 2.45	$ 2.36
Basic, pro forma	$ 2.64	$ 2.34	$ 2.26
Diluted, as reported	$ 2.68	$ 2.41	$ 2.30
Diluted, pro forma	$ 2.58	$ 2.30	$ 2.20

Revenue Recognition: Revenues for regulated natural gas sales to retail customers are recognized as service is rendered, including an accrual for unbilled revenues from the date of each meter reading to the end of the accounting period. 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. Revenues associated with all activities classified as energy trading were recognized in accordance with mark to market accounting through October 25, 2002. Subsequent to October 25, 2002, 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 in accordance with 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.

The NORESCO segment recognizes revenue and profit from long-term contracts, including turnkey energy savings performance contracts, using the percentage of completion method of accounting. The percentage of completion method measures the percentage of contract costs incurred to date to the estimated total contract costs for each contract. Contract costs include all direct material, labor, subcontract costs and those indirect costs related to contract performance. Revenue from contract change orders and claims is recognized when settlement is probable and the amount can be reasonably estimated. Costs and estimated profits in excess of billings are classified as a current asset. Amounts billed in excess of costs and estimated profits are classified as a current liability. NORESCO follows this method since reasonably dependable estimates of the revenue and costs applicable to various stages of a contract can be made. However, due to uncertainties inherent in the estimation process, actual results could differ from those estimates. Since the financial reporting of these contracts depends on estimates, which are assessed continually during the term of the contract, recognized revenues and profit are subject to revisions as the contract progresses to completion. The revenue recognized on contracts is not related to progress billings to customers. Revisions in profit estimates are reflected in the period in which the facts that give rise to the revision become known. Accordingly, favorable changes in estimates result in additional profit recognition, and unfavorable changes in estimates result in the reduction of previously recognized revenue and profits. The accuracy of the gross margins the Company reports for contracts is dependent upon various judgments it makes with respect to its contract performance, its cost estimates, and its ability to recover additional contract costs through change orders or claims. When estimates indicate a loss under a contract, cost of sales is charged with a provision for such loss in the period in which such losses are identified. As work progresses under a loss contract, revenues continue to be recognized, and a portion of the contract costs incurred in each period is charged to the contract loss reserve. The Company had no loss contracts as of December 31, 2003.

Balances billed but not paid by customers under retainage provisions in contracts were not significant at December 31, 2003. There were no significant amounts representing sales value of performance that had not been billed and were not billable to customers at December 31, 2003. There were no unbilled amounts representing claims or other similar items subject to uncertainty concerning their determination or ultimate realization that would be considered material enough for disclosure at December 31, 2003.

With certain projects, the Company enters into shared energy savings contracts to provide sustained levels of energy savings to its customers. The terms of the project are defined by an energy services agreement between the Company and the customer. Once completed, these projects will earn revenue from the customer based on the measurement formulas established in the energy services agreement. The Company recognizes revenue from shared energy savings contracts as energy savings are measured and verified, in accordance with the established measurement formulas.

Revenue received from customer contract termination payments is recognized when received. Any maintenance revenues are recognized as related services are performed.

Sales of Receivables: The Company, through its NORESCO segment, enters into construction contracts with governmental and institutional counterparties whereby those counterparties finance the construction directly with the Company at prevailing market interest rates. In order to accelerate cash collections and manage working requirements, the Company transfers these contract receivables due from customers to financial institutions. The transfer price of the contract receivables is based on the face value of the executed contract with the financial institution. The gain or loss on the sale of contract receivables is the difference between the existing carrying amount of the financial assets involved in the transfer and the transfer price of the contract with the financial institution.

Certain of these transfers do not immediately qualify as sales under SFAS No. 140 Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities (Statement No. 140). For the contract receivables that are transferred and still controlled by the Company, a liability is established to offset the cash received from the transfer. This liability is recognized until control has been surrendered in accordance with Statement No. 140, as the cash received by the Company can be called by the financial institution at the time it is determined that control will not be surrendered. The Company de-recognizes the receivables and the liabilities when control has been surrendered in accordance with the criteria provided in Statement No. 140. The Company does not retain any interests in the contract receivables once the sale is complete. As of December 31, 2003, the Company had recorded a current liability of $56.4 million classified as current portion of project financing obligations and a long-term liability of $49.0 million classified as project financing obligations on the Consolidated Balance Sheets. The current portion of project financing obligations represents transfers for which control is expected to be surrendered, and cash could be called, within one year. The related assets are classified as unbilled revenues as construction progresses and as other assets upon completion of construction.

For the year ended December 31, 2003, approximately $27.6 million of the contract receivables met the criteria for sales treatment generating a recognized gain of $0.4 million. The de-recognition of the $27.6 million in receivables and the related liabilities was a non-cash transaction and is consequently not reflected in the Statements of Consolidated Cash Flows.

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.

Accounting Principles Board No. 18, The Equity Method of Accounting for Investments in Common Stock (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. As discussed in Note 9, the Company recorded an impairment charge of $11.1 million in the fourth quarter of 2003 for its investment in Petroelectrica de Panama LDC, an independent power plant project in Panama.

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, Accounting for Certain Investments in Debt and Equity Securities (Statement No. 115). These investments are classified as investments, available-for-sale on the Consolidated Balance Sheet.

The Company owns approximately 11.53 million shares, or 17.1% of Westport, which decreased from 20.8% at the end of 2002. The Company does not have operational control of Westport. The decrease in the Company s ownership in Westport is a result of the Company s donation of 905,000 shares of Westport stock to a community giving foundation on March 31, 2003, the sale of approximately 1,260,000 shares on November 24, 2003 and the sale of 220,000 shares on December 22, 2003. The foundation was established by the Company and is projected to facilitate the Company s charitable giving program for approximately 10 years. The contribution resulted in charitable contribution expense of $9.3 million with a corresponding tax benefit of approximately $7.1 million (see Note 6).

As a result of the decreased ownership, the Company changed the accounting treatment for its investment in Westport from the equity method to available-for-sale, effective March 31, 2003. The change in accounting method eliminated the inclusion of Westport s results subsequent to March 31, 2003 in the Company s earnings. Also, the Company s investment in Westport was reclassified to investments, available-for-sale as of March 31, 2003, and was adjusted to fair market value, in accordance with Statement No. 115. The equity investment at the time it was reclassified totaled $134.1 million. As of June 30, 2003, the Company recorded a reclassification adjustment of $52.9 million to reduce accumulated other comprehensive income and increase common stock to reflect the increases in the book basis of the Company s investment in Westport from previous Westport capital transactions. Therefore, the total mark-to-market basis of the Westport investment was unchanged as of June 30, 2003, but the increase in common stock value will prospectively reduce any realized gains on the sale of Westport stock by the Company due to the increase in book basis to $16.53 per share from $10.25 per share.

The fair market value of the Company s investment in Westport was $344.2 million as of December 31, 2003 and was calculated based upon the quoted market price of Westport stock on that date. If the Company were to immediately liquidate its investment position in Westport, it would likely be at some discount to the quoted market price. The adjusted cost basis of the investment as of December 31, 2003 is $190.6 million. The increase in the carrying value of the investment of $153.6 million represents an unrealized gain on the investment which has been recorded in accumulated other comprehensive income net of applicable tax adjustments.

The Company has evaluated its investment policy in accordance with Statement No. 115 and has determined that all of its investment securities are appropriately classified as available-for-sale. Available-for-sale securities are required to be carried at fair value, with any unrealized gains and losses reported on the Consolidated Balance Sheet within a separate component of equity, accumulated other comprehensive income. The Company utilizes the specific identification method to determine the cost of the securities sold. The other available-for-sale securities maintained by the Company are intended to cover plugging and abandonment and other liabilities for which the Company self-insures and are not expected to be paid in the near future and are therefore considered long term in nature.

In accordance with Statement 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 2003 or 2002.

Income Taxes: The Company files a consolidated Federal income tax return. The Company 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 effective income tax rates are calculated for income from continuing operations, discontinued operations and cumulative effects of accounting changes.

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, Accounting for Income Taxes (Statement No. 109) which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of such temporary differences. The statement 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.

Allowance 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 the selling, general and administrative expense on the Statements of Consolidated Income. The reserve is 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 awards. See Note 18 for a detailed calculation.

Segment Disclosures: 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. Operating segments are evaluated on their contribution to the Company s consolidated results based on operating income, equity in earnings of nonconsolidated investments, excluding Westport, and minority interest. Interest charges and income taxes are managed on a consolidated basis. Headquarter 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.

Newly Adopted Accounting Standards: In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations (Statement No. 143). Statement No. 143 was adopted by the Company effective January 1, 2003, and its primary impact was to change the method of accruing for well plugging and abandonment costs. These costs were formerly recognized as a component of depreciation, depletion and amortization (DD&A) expense with a corresponding credit to accumulated depletion in accordance with SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies (Statement No. 19). At the end of 2002, the cumulative credit included within accumulated depletion totaled approximately $20.9 million. Statement 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 will increase 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 DD&A, and the initial capitalized costs are depleted over the useful lives of the related assets.

The adoption of Statement No. 143 by the Company resulted in an after-tax charge to earnings of $3.6 million, or $0.06 per diluted share, which is reflected as a cumulative effect of accounting change in the Company s

Statement of Consolidated Income for the year ended December 31, 2003. In addition to the charge to earnings, the depletion rate in the Company s Supply segment increased by $0.03 per Mcfe. The Company also recognized a $28.7 million other long-term liability and a $2.3 million long-term asset upon adoption of Statement No. 143. The long-term obligation represents the net present value of the estimated future expenditures required to plug and abandon the Company s approximately 12,000 wells in the Appalachian Basin, significant portions of which are not projected to occur for over 40 years.

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, 2003 (Thousands)
Asset retirement obligation as of beginning of period	$	28,690
Accretion expense		1,948
Liabilities incurred		431
Liabilities settled		(1,289)
Asset retirement obligation as of end of period	$	29,780

Assuming retroactive application of the change in accounting principle as of January 1, 2002, the pro forma effect of applying this new accounting principle on a retroactive basis would not materially change reported net income for the year ended December 31, 2002. Long-term liabilities, assuming retroactive application of the change in accounting principle as of January 1, 2002 and December 31, 2002, would have increased by $26.9 million and $28.7 million, respectively.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities (Statement No. 146), which superceded EITF No. 94-3, Liability Recognition for Certain Employment Termination Benefits and Other Costs to Exit an Activity. Statement No. 146 requires companies to record liabilities for costs associated with exit or disposal activities to be recognized only when the liability is incurred instead of at the date of commitment to an exit or disposal activity. Adoption of this Statement was effective for exit or disposal activities that were initiated after December 31, 2002. The adoption of this Statement did not have a material impact on its financial position, results of operations or cash flows.

In November 2002, the FASB issued Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (FIN No. 45). FIN No. 45 clarifies and expands on existing disclosure requirements for guarantees, including loan guarantees. It also required that, at the inception of a guarantee, the Company must recognize a liability for the fair value, of its obligation under that guarantee. The initial fair value recognition and measurement provisions are applied on a prospective basis to certain guarantees issued or modified after December 31, 2002. The disclosure provisions were effective for financial statements of periods ending after December 15, 2002. The adoption of FIN No. 45 did not have a material impact on the Company s financial position, results of operations or cash flows.

In November 2002, the EITF reached a consensus on Issue No. 00-21, Revenue Arrangements with Multiple Deliverables (EITF No. 00-21). EITF No. 00-21 provides guidance on how to account for arrangements that involve the delivery or performance of multiple products, services and rights to use assets. The provisions of EITF 00-21 apply to revenue arrangements entered into in the fiscal periods beginning after June 15, 2003. The adoption of EITF No. 00-21 did not have a material impact on the Company s financial position, results of operations or cash flows.

In January 2003, the FASB issued FASB Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN No. 46). FIN No. 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its

activities without additional subordinated financial support from other parties. Prior to FIN No. 46, an entity was generally consolidated by an enterprise when the enterprise had a controlling financial interest through ownership of a majority voting interest in the entity. FIN No. 46 is effective for all new variable interest entities created or acquired after January 31, 2003. The Company adopted FIN No. 46 for variable interest entities created or acquired prior to February 1, 2003 as of July 1, 2003. The adoption of FIN No. 46 required the consolidation of Plymouth Cogeneration Limited Partnership (Plymouth), a joint venture entered into by NORESCO, and the deconsolidation of EAL/ERI Cogeneration Partners LP (Jamaica), which is the partnership that holds the Jamaican power plant

During 1992, NORESCO entered into the Plymouth joint venture to construct, own and operate a cogeneration facility and provide electricity and steam to Plymouth State College. NORESCO originally recorded its interest in Plymouth on the Consolidated Balance Sheet as equity in unconsolidated investments. Under FIN No. 46, NORESCO is the primary beneficiary of Plymouth and began consolidating Plymouth in the consolidated financial statements effective July 1, 2003. The equity interests in Plymouth not owned by NORESCO are reported as a minority interest in the accompanying consolidated financial statements.

The consolidation of Plymouth removes the equity investment in Plymouth of $0.1 million and increases minority interest by $0.7 million, in the Consolidated Balance Sheet. As of December 31, 2003, the Company consolidated $4.7 million in assets and $4.1 million in total liabilities, including nonrecourse long-term debt of $4.0 million of which $0.2 million was classified as current.

NORESCO has a 91.2% interest in Jamaica and has historically consolidated Jamaica in the Company s financial statements. In the second quarter of 2002, the Company wrote off its entire investment in Jamaica due to poor performance. In the second quarter of 2003, ERI JAM, LLC, the entity that holds the Company s 91.2% interest in Jamaica declared bankruptcy and Jamaica stopped operations.

Upon adoption of FIN No. 46, it was determined that Jamaica was a variable interest entity and that the Company was not the primary beneficiary. As a result, the Company deconsolidated Jamaica effective July 1, 2003. The deconsolidation of Jamaica removed from the Consolidated Balance Sheet $17.8 million of assets and $18.0 million of total liabilities, including nonrecourse project financing of $15.9 million, all of which was current. The Company did not establish an equity method investment in Jamaica upon deconsolidation, as the amount of such investment would be less than zero and there is no recourse against the Company beyond its investment in Jamaica.

The Company also has an interest in a variable interest entity, Appalachian NPI (ANPI), in which Equitable was not deemed to be the primary beneficiary. As of December 31, 2003, ANPI had approximately $266.4 million of total assets and approximately $274.2 million of total liabilities (including $191.7 million of long-term debt, including current maturities), excluding minority interest. The Company s maximum exposure to a loss as a result of its involvement with ANPI is estimated to be $20.9 million.

In December 2003, the FASB issued a revision to FIN No. 46 (FIN No. 46R) to clarify some of the provisions of the interpretation and to exempt certain entities from its requirements. The Company is required to adopt the provisions of FIN No. 46R for interim periods ending after March 15, 2004. The Company is currently evaluating the impact that the adoption of this revision will have in its financial position, results of operations or cash flows.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (Statement No. 149). This Statement amends and clarifies the accounting and reporting for derivative instruments, including embedded derivatives, and for hedging activities under Statement No. 133. Statement No. 149 amends Statement No. 133 to reflect the decisions made as part of the

Derivatives Implementation Group (DIG) and in other FASB projects or deliberations. Statement No. 149 is effective for contracts entered into or modified after September 30, 2003, and for hedging relationships designated after September 30, 2003. The Company s accounting for derivative instruments is in compliance with Statement No. 149 and Statement No. 133. Therefore, the adoption of Statement No. 149 did not have a material impact on the Company s financial position, results of operations or cash flows.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity (Statement No. 150). This Statement requires that certain financial instruments embodying an obligation to transfer assets or to issue equity securities be classified as liabilities. It is effective for financial instruments entered into or modified after May 31, 2003 and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. The adoption of Statement No. 150 did not have a material impact on the Company s financial position, results of operations or cash flows.

In December 2003, the FASB issued SFAS No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits (Statement No. 132). This statement revises employers disclosures about pension plans and other postretirement benefits. It retains the original disclosure requirements contained in SFAS No. 132, Employers Disclosures about Pensions and Other Postretirement Benefits, and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. This Statement is effective for financial statements with fiscal years ending after December 15, 2003. Accordingly, the additional disclosures required by the revised Statement No. 132 have been included in Note 17. Interim period disclosures required by revised Statement No. 132 are effective for interim periods beginning after December 15, 2003.

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. In January 2004, the FASB issued Staff Position 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, (FSP FAS 106-1). This position permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Act. As permitted by FSP FAS 106-1, the Company has elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. In accordance with FSP FAS 106-1, appropriate disclosures related to the deferral election have been made in Note 17.

The American Institute of Certified Public Accountants has issued an exposure draft Statement of Position (SOP) Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment (PP&E). This proposed SOP applies to all nongovernmental entities that acquire, construct or replace tangible property, plant and equipment including lessors and lessees. A significant element of the SOP requires that entities use component accounting retroactively for all PP&E assets to the extent future component replacement will be capitalized. At adoption, entities would have the option to apply component accounting retroactively for all PP&E assets, to the extent applicable, or to apply component accounting as an entity incurs capitalizable costs that replace all or a portion of PP&E. The SOP is expected to be presented for FASB clearance in the first quarter of 2004 and would be applicable for fiscal years beginning after December 15, 2004. The Company is currently evaluating the impact that the adoption of this SOP would have on its financial position and results of operations.

Stock Split: On April 19, 2001, the Board of Directors of Equitable Resources declared a two-for-one stock split payable on June 11, 2001 to shareholders of record on May 11, 2001.

Reclassification: Certain previously reported amounts have been reclassified to conform to the 2003 presentation. These reclassifications did not affect reported net income or cash flows.

2. Financial Information by Business Segment

The Company reports its operations in three segments, which reflect its lines of business. Equitable Utilities operations comprise the sale and transportation of natural gas to customers at state-regulated rates, interstate pipeline 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 are comprised of 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. The NORESCO segment s activities are comprised of an integrated group of energy-related products and services that are designed to reduce its customers operating costs and improve their energy efficiency, including combined heat and power and central boiler/chiller plant development, design, construction, ownership and operation; performance contracting; and energy efficiency programs.

Previously, the Equitable Supply segment was referred to as Equitable Production. In 2002, the Company changed the name of this segment because it consists of two activities: production and gathering. The Company has provided additional disclosure on the two activities. This change does not impact the comparability of the business segment between years.

Operating segments are evaluated on their contribution to the Company s consolidated results based on operating income, equity in earnings of nonconsolidated investments, excluding Westport, and minority interest. Interest charges 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,		
	2003	2002	2001
		(Thousands)	
Revenues from external customers: (a)			
Equitable Utilities	$ 613,368	$ 754,273	$ 849,058
Equitable Supply	332,434	288,992	302,278
NORESCO	170,703	190,107	157,379
Less: intersegment revenues (b)	(69,228)	(164,304)	(199,381)
Total	$ 1,047,277	$ 1,069,068	$ 1,109,334
Depreciation, depletion and amortization:			
Equitable Utilities	$ 27,583	$ 26,894	$ 26,404
Equitable Supply	48,748	40,711	40,624
NORESCO	1,416	1,618	5,952
Headquarters	391	225	250
Total	$ 78,138	$ 69,448	$ 73,230
Operating Income:			
Equitable Utilities	$ 109,879	$ 101,929	$ 78,981
Equitable Supply	195,795	171,202	178,004
NORESCO	16,931	9,847	5,525
Unallocated expenses	(20,388)	(5,407)	(7,982)
Total operating income	$ 302,217	$ 277,571	$ 254,528
Reconciliation of operating income to net income:			
Equity in earnings (losses) of nonconsolidated investments, excluding Westport:			
Equitable Supply	$ 431	$ 282	$ 726
NORESCO (c)	(8,589)	4,699	7,555
Unallocated earnings	149	32	
Total	$ (8,009)	$ 5,013	$ 8,281
Minority interest:			
Equitable Supply	$ (871)	$ (7,103)	$
NORESCO	(542)		

Total	$ (1,413)	$ (7,103)	$
Charitable foundation contribution	(9,279)		
Gain on sale of available for sale securities	13,985		
Westport equity earnings (losses)	3,614	(8,476)	17,820
Interest expense	45,766	38,787	41,098
Income tax expense	81,792	77,592	87,723
Income from continuing operations before cumulative effect of accounting change	173,557	150,626	151,808
Income from discontinued operations		9,000	
Cumulative effect of accounting change, net of tax (d)	(3,556)	(5,519)	
Net income	$ 170,001	$ 154,107	$ 151,808

	Years Ended December 31,		
	2003	2002	2001
		(Thousands)	
Significant noncash expense items:			
Equitable Utilities:			
Increase (decrease) in deferred purchased natural gas cost	$ 3,553	$ (9,231)	$ (6,493)
Regulatory asset valuation allowance			7,000
Equitable Supply:			
Lease and gathering system impairments			2,410
NORESCO:			
Impairment of long-lived assets		5,320	
Total	$ 3,533	$ (3,911)	$ 2,917
Segment assets:			
Equitable Utilities	$ 1,120,708	$ 929,718	$ 937,147
Equitable Supply	1,338,702	1,079,924	1,138,550
NORESCO (e)	323,569	269,707	264,960
Total operating segments	2,782,979	2,279,349	2,340,657
Headquarters assets, including cash and short-term investments	156,913	157,542	178,090
Total	$ 2,939,892	$ 2,436,891	$ 2,518,747
Expenditures for segment assets:			
Equitable Utilities	$ 60,414	$ 70,188	$ 38,528
Equitable Supply (f)	204,527	147,461	93,862
NORESCO	307	698	289
Other	451	147	152
Total	$ 265,699	$ 218,494	$ 132,831

(a) Operating revenues for 2001 have been reclassified to reflect the impact of EITF No. 02-3.

(b) Intersegment revenues in 2002 and 2001 represent sales from Equitable Supply to the unregulated marketing affiliate of Equitable Utilities, which marketed all of Equitable Supply s production in 2002 and 2001. In 2003, Equitable Supply assumed the marketing of a substantial portion of its operated volumes and recorded the marketing activity directly.

(c) Equity earnings (losses) for 2003 include a $11.1 million charge related to the impairment of an equity investment in Petroelectrica de Panama LDC. See Note 9.

(d) Net income for the years ended December 31, 2003 and December 31, 2002 has been adjusted to reflect the cumulative effect of accounting change related to the adoption of Statement No. 143 and No. 142, respectively. See Note 1.

(e) The Company s goodwill balance as of December 31, 2003 and December 31, 2002 totaled $51.8 million and is entirely related to the NORESCO segment. See Note 12.

(f) 2003 expenditures include $44.2 million for the acquisition of the remaining 31% limited partner interest in Appalachian Basin Partners, LP. See Note 5.

3. 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. 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 was a $34.5 million asset and a $137.6 million liability as of December 31, 2003, and a $30.9 million asset and a $25.0 million liability as of December 31, 2002. These amounts are classified in the Consolidated Balance Sheets as derivative commodity instruments, at fair value. The decrease in the net amount of derivative commodity instruments, at fair value, from December 31, 2002 to December 31, 2003 is primarily the result of the increase 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 347.2 Bcf and 265.1 Bcf as of December 31, 2003 and 2002, respectively, and primarily relate to natural gas swaps. The open swaps at year-end 2003 have maturities extending through December 2010.

The Company deferred a net loss of $58.4 million and a net gain of $2.8 million in accumulated other comprehensive income, net of tax, as of December 31, 2003 and 2002, 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 $22.9 million of net unrealized losses on its derivative commodity instruments reflected in accumulated other comprehensive loss as of December 31, 2003 will be recognized in earnings during the next twelve months due to the physical settlement of hedged transactions.

During the year ended December 31, 2003, the net change in accumulated other comprehensive income related to derivatives was a loss of $61.1 million, net of tax. This was comprised of a $28.8 million net realized loss which was reclassified from accumulated other comprehensive income to earnings and a net unrealized loss of $89.9 million. During the year ended December 31, 2002, the net change in accumulated other comprehensive income related to derivatives was a loss of $99.7 million, net of tax. This was comprised of a $14.5 million net realized loss which was reclassified from accumulated other comprehensive income to earnings and a net unrealized loss of $114.2 million. During the year ended December 31, 2001, the net change in accumulated other comprehensive loss related to derivatives was a gain of $139.5 million, net of tax. This was comprised of a $0.8 million net realized gain which was reclassified from accumulated other comprehensive loss to earnings and a net unrealized gain of $140.3 million.

For the years ended December 31, 2003 and 2002, ineffectiveness associated with the Company s derivative commodity instruments designated as cash flow hedges (decreased) increased earnings by approximately $(2.9) million and $1.5 million, respectively. These amounts are included in operating revenues in the Statements of Consolidated Income. There was no ineffectiveness for the year ended December 31, 2001.

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, 2003, the absolute notional quantities of the futures and swaps held for trading purposes totaled 1.1 Bcf and 54.0 Bcf, respectively.

Below is a summary of the activity of the fair value of the Company s derivative contracts with third parties held for trading purposes during the year ended December 31, 2003 (in thousands).

Fair value of contracts outstanding as of December 31, 2002	$	6,623
Contracts realized or otherwise settled		(295)
Other changes in fair value		(6,155)
Fair value of contracts outstanding as of December 31, 2003	$	173

There were no 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, 2003 and 2002.

The following table presents the maturities and the fair valuation source for the Company s derivative commodity instruments that are held for trading purposes as of December 31, 2003.

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

Source of Fair Value	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
			(Thousands)		
Prices actively quoted (NYMEX) (1)	$ 22	$ 164	$	$	$ 186
Prices provided by other external sources (2)	(81)	57	11		(13)
Net derivative (liabilities) assets	$ (59)	$ 221	$ 11	$	$ 173

(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 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 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 hedged 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 as applicable, anticipated transactions occur as expected.

4. Sale of Property

In December 2001, the Company sold its oil-dominated fields in order to focus on natural gas activities. The sale resulted in a decrease of 63 Bcfe of proved developed producing reserves and 5 Bcfe of proved undeveloped reserves for proceeds of approximately $60 million. The field produced approximately 4 Bcfe annually. Although the Company no longer operates these properties, it continues to gather and market the natural gas produced for a fee. During 2003 and 2002, these fees were approximately $1.7 million and $1.5 million, respectively.

In February 2003, the Company sold approximately 500 of its low-producing natural gas wells, within two of its non-strategic districts, in two separate transactions. The sales resulted in a decrease of 13.0 Bcf of net reserves and generated proceeds of approximately $6.6 million. The wells produced an aggregate of approximately 1.0 Bcf in 2002. The Company did not recognize a gain or a loss as a result of this disposition.

5. Acquisitions

In February 2003, the Company purchased the remaining 31% limited partnership interest in Appalachian Basin Partners, LP (ABP) from the minority interest holders for $44.2 million. The 31% limited partnership interest represents approximately 60.2 Bcf of reserves. The ABP partnership was formed in November 1995 when the Company monetized Appalachian gas properties qualifying for the nonconventional fuels tax credit. The Company retained a partnership interest in the properties that increased substantially based on the attainment of a performance target, which was met near the end of 2001. The Company consequently consolidated the partnership starting in 2002, and the remaining portion not owned by the Company was recorded as minority interest. As a result of the purchase of the 31% limited partner interest, effective February 1, 2003, the Company no longer recognized minority interest expense associated with ABP, which totaled $0.9 million and $7.1 million for the years ended December 31, 2003 and 2002, respectively.

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, 2003	December 31, 2002
	(Thousands)	
Deferred tax liabilities (assets):		
Drilling and development costs expensed for income tax reporting	$ 267,013	$ 220,213
Other comprehensive income (loss)	2,084	(11,173)
Tax depreciation in excess of book depreciation	221,698	173,560
Regulatory temporary differences	24,507	30,861
Deferred purchased gas cost	(972)	4,317
Undistributed earnings of foreign subsidiaries	1,047	5,121
Deferred revenues/expenses	(16,421)	(15,586)
Alternative minimum tax	(28,060)	(19,833)
Investment tax credit	(4,759)	(5,203)
Uncollectible accounts	(6,495)	(2,697)
Postretirement benefits	(5,820)	(4,563)
Other	(1,412)	(22,707)
Total (including amounts classified as current assets of $7,467 for 2003 and current liabilities of $1,620 for 2002)	$ 452,410	$ 352,310

The net deferred tax liabilities relating to the Company s other comprehensive income balance as of December 31, 2003 were comprised of a $54.0 million deferred tax liability relating to the Company s net unrealized gain on available-for-sale securities, a $38.7 million deferred tax asset relating to the Company s net unrealized loss from hedging transactions and a $13.2 million deferred tax asset related to the minimum pension adjustment. The net deferred tax assets relating to the Company s other comprehensive income balance as of December 31, 2002 were comprised of a $1.5 million deferred tax liability relating to the Company s net unrealized gain from hedging transactions, and a $12.7 million deferred tax asset related to the minimum pension adjustment.

Income tax expense is summarized as follows:

	Years Ended December 31, 2003	2002	2001
		(Thousands)	
Current:			
Federal	$ 7,109	$ 28,790	$ 24,686
State	5,599	5,647	697
Foreign		286	
Subtotal	$ 12,708	$ 34,723	$ 25,383

Deferred:						
Federal		66,675		38,360		61,844
State		2,409		3,968		496
Foreign				541		
Subtotal		69,084		42,869		62,340
Total	$	81,792	$	77,592	$	87,723

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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,		
	2003	2002	2001
		(Thousands)	
Tax at statutory rate	$ 89,371	$ 79,876	$ 83,836
State income taxes	5,206	6,250	734
Differences from foreign operations, including foreign taxes	(5,140)	1,865	4,581
Nonconventional fuels tax credit	(2,095)	(9,415)	(1,000)
Percentage depletion basis differences	(1,958)		
Charitable contribution basis differences	(3,162)		
Other	(430)	(984)	(428)
Income tax expense	$ 81,792	$ 77,592	$ 87,723
Effective tax rate	32.0%	34.0%	36.6%

Separate effective income tax rates are calculated for income from continuing operations, discontinued operations and cumulative effects of accounting changes. See Note 7 as to the tax impact of discontinued operations and Note 1 and Note 12 as to the tax impact of cumulative effects of accounting changes.

An income tax benefit of $9.3 million, $7.3 million and $2.6 million for the years ended December 31, 2003, 2002 and 2001, respectively, triggered by the exercise of nonqualified employee stock options, is reflected as an addition to common stockholders equity.

As a result of the donation on March 31, 2003 of appreciated shares of Westport Resources Corporation to a charitable foundation created by the Company (see Note 9), the Company reported a tax benefit of approximately $7.1 million. A gift of qualified appreciated stock allows for a tax deduction based on the fair market value of the gifted stock, resulting in a permanent tax benefit of $3.9 million ($3.2 million related to Federal taxes and $0.7 million related to state taxes) that reduces the effective income tax rate.

As a result of the Company s increased partnership interest in ABP in 2002, the Company began receiving a greater percentage of the nonconventional fuels tax credit attributable to ABP. This resulted in a reduction of the Company s effective tax rate during 2002. The nonconventional fuels tax credit expired at the end of 2002 and it is currently unclear whether legislation will be enacted to allow this tax benefit to exist in the future. The Company s effective tax rate was reduced in 2003 for nonconventional fuels tax credits not recorded in prior years.

The consolidated Federal income tax liability of the Company has been settled with the Internal Revenue Service (IRS) through 1997. The IRS is currently reviewing the Company s federal income tax filings for the 1998 through 2000 years. The Company also is the subject of various routine state income tax examinations. The Company does not believe that these reviews will result in any adjustments that will have a negative impact on net income.

The Company has an AMT credit carryforward of $28.1 million at December 31, 2003 that it believes will be utilized against future Federal income tax liabilities. The Company has recorded a deferred tax asset of $2.7 million, net of valuation allowances and federal taxes, related to state net operating loss carryforwards with various expiration dates that are expected to be utilized against future state income tax liabilities.

7. Discontinued Operations

In April 1998, management adopted a formal plan to sell the Company s natural gas midstream operations. A capital loss was treated as a nondeductible item for tax reporting purposes under the then current Treasury regulations embodying the loss disallowance rule, resulting in additional tax recorded on this sale as a reduction to income from discontinued operations. In May 2002, the IRS issued new Treasury regulations interpreting the loss disallowance rule that now permit this capital loss to be treated as deductible. During June 2002, the Company filed an amended tax return. Consequently, in the second quarter 2002, the Company recorded a $9.0 million increase in income from discontinued operations related to this unexpected tax benefit.

8. Restricted Cash

In 2001, the net proceeds from the sale of certain properties were placed in an escrow account pursuant to a deferred exchange agreement. This agreement allowed for the use of the funds in a potential like-kind exchange for certain identified assets. During 2002, the restrictions lapsed and the cash was made available for operations.

9. Equity in Nonconsolidated Investments

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

Investees	**Location**	**Interest Type**	**Ownership as of December 31, 2003**	**December 31,**	
				2003	**2002**
				(Thousands)	
Eastern Seven Partners, L.P.	USA	Limited	1%	$ 26,055	$ 26,136
Appalachian Natural Gas Trust	USA	Limited	1%	35,745	36,075
Total Equitable Supply				$ 61,800	$ 62,211
IGC/ERI Pan-Am Thermal Generating Limited	Panama	Limited	50%	$ 21,693	$ 19,976
Petroelectrica de Panama LDC	Panama	Limited	45%		12,213
Capital Center Energy Company LLC	USA	Limited	0%		4,374
Compania Hidroeletrico Dona Julia, S.D.R. Ltd.	Costa Rica	Limited	24%	5,639	5,108
Hunterdon Cogeneration LP	USA	General	50%		2,066
Plymouth Cogeneration LP	USA	Limited	28%		102
Other	USA	Limited	Various	43	36
Total NORESCO				27,375	43,875
Westport Resources Corporation	USA		17%		139,706
Total equity in nonconsolidated investments				$ 89,175	$ 245,792

The Company did not make any additional equity investments in nonconsolidated investments during 2003 or 2002 and has a total cumulative investment in nonconsolidated entities of $89.2 million as of December 31, 2003. The Company s ownership share of the earnings for 2003, 2002 and 2001 related to the total investments, excluding Westport was $3.1 million, $5.0 million and $8.3 million, respectively. All NORESCO segment projects have been completed using nonrecourse financing at the nonconsolidated entity level.

The NORESCO segment has investments in unconsolidated partnerships. These investments represent equity ownership interests in independent power plant (IPP) projects located in the United States as well as in selected international countries.

IPP projects which NORESCO and its partners developed, constructed and operate are the result of specific needs of private or governmental entities to secure power that is more cost effective and reliable than the current source of power as well as to meet the growing energy demands of many international countries. Long-term power purchase agreements are signed with the customer whereby they agree to purchase the energy generated by the plant. The length of these contracts ranges from 1 to 7 years.

The Company reviewed its equity investment related to Petroelectrica de Panama, an independent power plant project in Panama, during the fourth quarter of 2003 as the project was unsuccessful in securing power capacity contracts. Moreover, the market prices for power supply in Panama make it uneconomical to operate the plant. As a result, the plant was shut down in January 2004. The Company is evaluating various options including the closing of the plant, both temporarily and permanently, and the sale of the plant. As part of the impairment analysis, the Company performed a probability cash flow analysis using the undiscounted future cash flows and compared this amount to the book value of the equity investment. The probability cash flows resulted in a lower fair value than the carrying value, and an impairment was deemed necessary. An impairment of $11.1 million was recorded and represents the full value of NORESCO s equity investment in the project.

The Company owned a 50% interest in Capital Center Energy Company LLC, the supplier of power and conditioned air to a mall located in Providence, RI. On October 31, 2003, the Company sold its interest in the project entities to the mall owner. The Company recorded an immaterial gain on the sale.

In June 2003, the Company reevaluated its interest in Hunterdon Cogeneration LP (Hunterdon) and concluded that the Company effectively controls Hunterdon for consolidation purposes. As a result, the Company began consolidating Hunterdon s financial position, results of operations and cash flows as of June 30, 2003.

The Company adopted FIN No. 46 for variable interest entities created or acquired prior to February 1, 2003 as of July 1, 2003. The adoption of FIN No. 46 required the consolidation of Plymouth Cogeneration LP s (Plymouth) financial position, results of operations and cash flows as of July 1, 2003, as NORESCO is the primary beneficiary of Plymouth.

On April 10, 2000, Equitable Resources merged its Gulf of Mexico operations with Westport Oil and Gas Company for debt repayment of approximately $50 million in cash and approximately 49% of a minority interest in the combined company, named Westport Resources Corporation (Westport). Equitable Resources accounted for this investment under the equity method of accounting. In October 2000, Westport completed an initial public offering (IPO) of its shares. Equitable Resources sold 1.325 million shares in this IPO for an after-tax gain of $4.3 million. On August 21, 2001, Westport completed a merger with Belco Oil & Gas. On March 31, 2003, the Company donated 905,000 shares to a community giving foundation. Consistent with the Company s previously disclosed intention to continue to reduce its percentage ownership in Westport, the Company sold approximately 1,260,000 shares of Westport, with a book value of $16.53 per share, at $25.55 per share in November 2003. This sale created a gain of approximately $11.4 million. The Company sold an additional 220,000 shares of Westport in December 2003 at $28.51 per share. This sale created a gain of approximately $2.6 million. The cash proceeds from these sales were used to fund contributions to the Company s defined benefit pension plans. As a result, the Company currently owns approximately 11.53 million shares, or 17.1% of Westport, a decrease from 20.8% at the end of 2002. The Company does not have operational control of Westport.

As discussed in Note 1, as a result of the decreased ownership, the Company changed the accounting treatment for its investment from the equity method to available-for-sale, effective March 31, 2003. The Company has announced its desire to sell additional shares so that the aggregate number of shares of Westport common stock sold in the six months subsequent to October 2003 equals approximately 3,000,000. The additional sales may occur through an underwritten offering, a registered, negotiated transaction, additional Rule 144 transactions or as otherwise permitted under the Registration Rights Agreement. The Company is engaged in discussions with Westport regarding appropriate means of effecting these additional sales. The foregoing is subject to the terms of a Registration Rights Agreement with Westport. This Form 10-K does not constitute an offer of any securities for sale. The sale of any Westport common stock by the subsidiary will be made only by means of a prospectus or pursuant to an exemption from registration.

Equitable Supply s equity in nonconsolidated investments represents ownership interests in transactions by which natural gas producing properties located in the Appalachian Basin region of the United States were sold. Both of these investments follow the equity method of accounting.

In 2002, Equitable Supply transferred one-third of its ownership in ANGT to an affiliated company. As of December 31, 2003 and 2002, Equitable Supply s investment in ANGT totaled $ 23.8 million and $24.1 million, respectively, while the Company s total investment was $35.7 million and $36.1 million, respectively.

The following tables summarize the financial information for nonconsolidated investments accounted for under the equity method of accounting:

Summarized Balance Sheets

	December 31, 2003	
	Supply	NORESCO
	(Thousands)	
Current assets	$ 17,412	$ 35,499
Noncurrent assets	352,373	119,021
Total assets	$ 369,785	$ 154,520
Current liabilities	$ 28	$ 17,551
Noncurrent liabilities		60,375
Stockholders equity	369,757	76,594
Total liabilities and stockholders equity	$ 369,785	$ 154,520

		December 31, 2002	
	Supply	NORESCO	Westport
		(Thousands)	
Current assets	$ 16,216	$ 46,111	$ 144,529
Noncurrent assets	379,663	164,420	2,089,012
Total assets	$ 395,879	$ 210,531	$ 2,233,541
Current liabilities	$ 1,207	$ 27,106	$ 155,597
Noncurrent liabilities		94,469	945,938
Stockholders equity	394,672	88,956	1,132,006
Total liabilities and stockholders equity	$ 395,879	$ 210,531	$ 2,233,541

Summarized Statements of Income

	Year Ended December 31, 2003	
	Supply	NORESCO
	(Thousands)	
Revenues	$ 117,174	$ 84,557
Costs and expenses applicable to revenues		1,337
Net revenues	117,174	83,220
Operating expenses	60,298	67,207
Operating income	56,876	16,013
Other expense		7,833
Income tax expense		767
Net income	$ 56,876	$ 7,413

	Year Ended December 31, 2002		
	Supply	NORESCO	Westport
		(Thousands)	
Revenues	$ 86,934	$ 79,728	$ 428,430
Costs and expenses applicable to revenues		1,146	28,862
Net revenues	86,934	78,582	399,568
Operating expenses	61,722	64,031	414,624
Operating income (loss)	25,212	14,551	(15,056)
Other expense		2,103	33,062
Income tax expense (benefit)		1,830	(19,552)
Net income	$ 25,212	$ 10,618	$ (28,566)

	Year Ended December 31, 2001		
	Supply	NORESCO	Westport
		(Thousands)	
Revenues	$ 116,843	$ 88,364	$ 317,278
Costs and expenses applicable to revenues		3,826	(31,582)
Net revenues	116,843	84,538	348,860
Operating expenses	70,249	60,123	264,045
Operating income	46,594	24,415	84,815
Other expense		2,360	6,357
Income tax expense		4,806	28,637
Net income	$ 46,594	$ 17,249	$ 49,821

10. Investments

Investments classified as available-for-sale consist of approximately $19.1 million of debt and equity securities that are intended to fund plugging and abandonment and other liabilities for which the Company self-insures. For fiscal year 2003, investments classified as available-for-sale also include the $344.2 million investment in Westport. As discussed in Notes 1 and 9, the Company changed its accounting treatment for its investment in Westport in the first quarter of 2003 from the equity method to available-for-sale, effective March 31, 2003. The Company utilizes the specific identification method to determine the cost of securities sold. Gross gains of $14.0

million were realized during the year ended December 31, 2003 related to the sale of 1.48 million shares of Westport stock. There were no realized gains or losses associated with the investments for the year ended December 31, 2002. Any unrealized gains or losses are recognized within the Consolidated Balance Sheet as a component of equity, accumulated other comprehensive income. Information regarding the cost and fair value of the Company s available-for-sale investments at December 31, 2003 and December 31, 2002 is presented in the tables below. As of December 31, 2003, the corporate notes and bonds have not been in a continuous unrealized loss position for more than twelve months. The Company performed an impairment analysis in accordance with Statement No. 115 and concluded that the decline below cost is temporary.

	December 31, 2003			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(Thousands)		
Investment in Westport	$ 190,557	$ 153,668	$	$ 344,225
Other corporate equity securities	10,824	928		11,752
Corporate notes and bonds	7,479		(176)	7,303
Total investments	$ 208,860	$ 154,596	$ (176)	$ 363,280

	December 31, 2002			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(Thousands)		
Corporate equity securities	$ 10,666	$ 429	$ (1,947)	$ 9,148
Corporate notes and bonds	6,926	196	(172)	6,950
Total investments	$ 17,592	$ 625	$ (2,119)	$ 16,098

11. Regulatory Assets

The following table summarizes the Company s regulatory assets, net of amortization, as of December 31, 2003 and 2002. The Company believes that it will continue to be subject to rate regulation that will provide for the recovery of these assets.

	December 31,	
Description	2003	2002
	(Thousands)	
Deferred taxes (Statement No. 109)	$ 54,500	$ 56,424
Delinquency Reduction Opportunity Program	12,478	23,403
Other postemployment benefits (Statement No. 106)	6,305	5,345
Deferred purchase gas costs (credits)	1,396	(2,157)
Other	1,431	1,439
Valuation allowance	(7,000)	(7,000)
Total regulatory assets	69,110	77,454

Amounts classified as other current assets (liabilities)		1,396		(2,157)
Total long-term regulatory assets	$	67,714	$	79,611

The regulatory asset associated with deferred taxes primarily represents timing differences associated with the excess of federal tax depreciation over book depreciation on property, plant and equipment associated with

Equitable Utilities operations resulting from the adoption of Statement No. 109 in 1993. The Company is recovering the amortization of this asset through rates.

The following regulatory assets do not earn a return on investment: deferred taxes (Statement No. 109), Delinquency Reduction Opportunity Program and other postemployment benefits (SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions). The associated remaining recovery periods for these regulatory assets are 34 years, 10 years and 10 years, respectively.

A regulatory asset was recognized as of December 31, 2001 at the distribution company associated with uncollectible accounts receivable mainly due to 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 the third quarter 2002, the PA PUC issued an order approving a Delinquency Reduction Opportunity Program that gives incentives to low-income customers to make payments, which 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. The Company has established a valuation allowance of $7.0 million as of December 31, 2002 and 2003 against the accounts receivable special arrears regulatory asset relating to the portion of the balance where collection does not appear probable due to the nature of the regulatory asset.

The Company completes quarterly purchased gas cost filings with the PA PUC that are subject to quarterly reviews and annual audits by the PA PUC. The PA PUC completed its most recent audit in 2001, which approved the Company s purchased gas costs through 1999. The PA PUC Audit Bureau has commenced an audit of the 2000-2001 purchased gas period. The on-site audit concluded in the fourth quarter of 2003. A final audit report for the 2000-2001 period is expected by the end of the second quarter of 2004. The Company s purchased gas costs for 2000-2003 are currently unaudited by the PA PUC, but have received a final prudency review by the PA PUC through 2002 in which no material issues have been noted.

Over the last three years, Equitable Gas has been working with state regulators to shift the manner in which costs are recovered from traditional cost of service rate making to performance-based rate making. In 2001, Equitable Gas received approval from the PA PUC to implement a performance-based incentive that provides customers a purchased gas cost credit which is fixed in amount, while enabling Equitable Gas to retain all revenues in excess of the credit through more effective management of upstream interstate pipeline capacity. During the third quarter 2002, the PA PUC approved a one-year extension of this program through September 2004. In that same order, the PA PUC approved a second performance-based initiative related to balancing services. This initiative runs through 2005. During the second quarter of 2003, Equitable Gas reached a settlement with all parties to extend its performance-based purchased gas cost credit incentive through September 2005. The settlement also included a new performance-based incentive, which allows Equitable to retain 25% of any revenue generated from a new service designed to increase the recovery of capacity costs from transportation customers. A PA PUC Order approving the settlement was issued in September 2003.

In the second quarter 2002, the PA PUC authorized Equitable Gas to offer a sales service that would give residential and small business customers the alternative to fix the unit cost of the commodity portion of their rate. The program was developed in response to customer requests for a method to reduce the fluctuation in gas costs. This first of its kind program in Pennsylvania is another in a series of service-enhancing initiatives implemented by Equitable Gas. A competitor, Dominion Retail, Inc., appealed the PA PUC order authorizing the new service to the Commonwealth Court of Pennsylvania. In September 2003, the Commonwealth Court of Pennsylvania issued an order affirming the PA PUC decision granting Equitable Gas authority to implement the new Fixed Sales Service. To date, Equitable Gas not offered Fixed Sales Service but will continue to analyze the feasibility of a Fixed Sales Service in the future.

12. Intangible Assets

In accordance with the requirements of Statement No. 142, the Company tested its goodwill for impairment as of January 1, 2002. The Company s goodwill balance as of January 1, 2002 totaled $57.2 million and is entirely related to the NORESCO segment. The fair value of the Company s goodwill was estimated using discounted cash flow methodologies and market comparable information. As a result of the 2002 impairment test, the Company recognized an impairment of $5.5 million, net of tax, to reduce the carrying value of the goodwill to its estimated fair value as the level of future cash flows from the NORESCO segment were expected to be less than originally anticipated. In accordance with Statement No. 142, this impairment adjustment was reported as the cumulative effect of an accounting change in the Company s Statements of Consolidated Income retroactive to the first quarter 2002. The tax impact of the impairment was zero since the Company s goodwill has no tax basis. In the fourth quarter of 2003 and 2002, the Company performed the required annual impairment test of the carrying amount of goodwill and no further impairment was required.

Prior to the adoption of Statement No. 142 in 2002, amortization of the goodwill was provided on the straight-line method over a life of 20 years. Accumulated amortization at December 31, 2001 was $17.5 million. For the year ended December 31, 2001 amortization expense, included in depreciation, depletion and amortization, was $3.7 million. In accordance with Statement No. 142, there was no amortization expense for the years ended December 31, 2003 and 2002.

Had the Company accounted for its goodwill under Statement No. 142 as of January 1, 2001, net income for fiscal year 2001 would have increased by $3.7 million to $155.5 million and diluted earnings per share would have increased by $0.06 per share.

13. Short-Term Loans

Maximum lines of credit of $500 million were available to the Company at December 31, 2003 and 2002, respectively. The Company is not required to maintain compensating bank balances. The Company s credit ratings, as determined by either Standards & 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 credit rating, the higher the level of fees and borrowing rate. As of December 31, 2003, the Company had not borrowed any amounts against these lines of credit. Commitment fees averaging one-eleventh of one percent in both 2003 and 2002 were paid to maintain credit availability.

Short-term loans were comprised of commercial paper balances of $199.6 million and $106.0 million with weighted average annual interest rates of 1.08% and 1.37% as of December 31, 2003 and 2002, respectively. The maximum amount of outstanding short-term loans at any certain time during the year was $229.6 million in 2003 and $303.6 million in 2002. The average daily balance of short-term loans outstanding over the course of the year was approximately $106.1 million and $211.7 million at weighted average annual interest rates of 1.19% and 1.81% during 2003 and 2002, both respectively.

14. Long-Term Debt

	December 31, 2003	2002
	(Thousands)	
5.15% notes, due March 1, 2018	$ 200,000	$
5.15% notes, due November 15, 2012	200,000	200,000
7.75% debentures, due July 15, 2026	115,000	115,000
Medium-term notes:		
8.0% to 9.0% Series A, due 2003 thru 2021	53,500	62,750
6.5% to 7.6% Series B, due 2003 thru 2023	60,500	75,500
6.8% to 7.6% Series C, due 2007 thru 2018	18,000	18,000
Other	6,414	
	653,414	471,250
Less debt payable within one year	21,267	24,250
Total notes and debentures	632,147	447,000
Nonrecourse note for project financing		16,055
Less current portion of nonrecourse note for project financing		16,055
Long-term portion of nonrecourse note for project financing		
Total long-term debt	$ 632,147	$ 447,000

In February 2003, the Company issued $200 million of Notes with a stated interest rate of 5.15% and a maturity date of March 2018. A portion of the proceeds from the issuance were used to redeem the Company s entire $125 million of 7.35% Trust Preferred Capital Securities on April 23, 2003. No gain or loss was incurred as a result of this redemption. The remainder of the proceeds from the February 2003 issuance was designated for general corporate purposes. The effective annual interest rate on the $200 million of notes is 5.22% after taking into consideration capitalized transaction costs and fees associated with the offering. Effective September 30, 2003, the Company offered all holders of its 5.15% Notes due 2018 the opportunity to exchange their Notes for a new issue of registered Notes pursuant to a Registration Statement on Form S-4. The exchange Notes are identical in all material respects to the Notes being exchanged, except that the exchange Notes do not have terms restricting their transfer or any terms related to registration rights. All original Notes have been exchanged for the new issue of registered Notes as of December 31, 2003.

As of December 31, 2003, the Company has the ability to issue $100 million of additional long-term debt under the provisions of shelf registrations filed with the Securities and Exchange Commission.

The Company issued $200 million of notes on November 15, 2002 with a stated interest rate of 5.15% and a maturity date of November 15, 2012 to pay down commercial paper. In September 2002, the Company entered into interest rate swap agreements with a notional amount of $150 million to hedge the risk of movement in interest rates from the date of the swap agreements to the date of issuance of the long-term debt. On November 15, 2002, shortly after the issuance of the long-term debt, the Company terminated the swap agreements by remitting approximately $1.2 million to the counterparties to the agreements. As these swap agreements were designated at inception as being cash flow hedges and were deemed to be effective, the $1.2 million was included in accumulated other comprehensive income on the Consolidated Balance Sheets and will be reclassified to interest expense in the periods in which the Company s earnings are impacted by the hedged item. The Company estimates that approximately $0.1 million of the net unrealized losses related to the settlement of its interest rate swaps will be recognized in earnings during the next twelve months. The effective annual interest rate on the $200 million of notes is 5.30% after taking into consideration capitalized transaction costs and fees associated with the offering and the effect of the $150 million of interest rate swap agreements that were settled upon issuance of the long-term debt.

Other primarily consists of long-term debt obligations of Hunterdon and Plymouth, which were consolidated during 2003. See Note 9 for further discussion on the consolidation of Hunterdon and Plymouth.

During the first quarter of 2001, a Jamaican energy infrastructure project, a consolidated subsidiary, experienced defaults relating to various loan covenants. Consequently, the Company reclassified the nonrecourse project financing from long-term debt to current liabilities. As this debt was nonrecourse to the Company, it was not included in the aggregate maturities of long-term debt stated above for 2002. In the second quarter of 2003, ERI JAM LLC, the entity that held the Company s 91.2% interest in Jamaica declared bankruptcy and Jamaica stopped operations. Upon adoption of FIN No. 46, it was determined that Jamaica was a variable interest entity and that the Company was not the primary beneficiary. As a result, the Company deconsolidated Jamaica effective July 1, 2003. The deconsolidation removed the full amount of the nonrecourse project financing.

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.

Interest expense on long-term debt amounted to $39.3 million in 2003, $23.8 million in 2002 and $23.3 million in 2001. Aggregate maturities of long-term debt are $21.3 million in 2004, $10.8 million in 2005, $3.9 million in 2006, $11.0 million in 2007, and $0.3 million in 2008.

15. Prepaid Gas Forward Sales

In 2000, the Company entered into two prepaid natural gas sales contracts for 52.7 Bcf of reserves. The Company is required to sell and deliver certain quantities of natural gas during the term of the contracts. The first contract is for five years with net proceeds of $104.0 million. The second contract was for three years with net proceeds of $104.8 million and was completed at the end of 2003. These contracts were recorded as prepaid forward sales and are recognized in income as deliveries occur.

As of December 31, 2003 and 2002, the outstanding prepaid gas forward sale balances totaled $41.6 million and $97.3 million, respectively, of which $20.8 million was current for 2003 and $55.7 million was current for 2002.

16. Trust Preferred Capital Securities

In April 1998, $125 million of 7.35% trust preferred capital securities were issued. The capital securities were issued through a subsidiary trust, Equitable Resources Capital Trust I, established for the purpose of issuing the capital securities and investing the proceeds in 7.35% Junior Subordinated Debentures issued by the Company. The capital securities had mandatory redemption date of April 15, 2038; however, at the Company s option, the securities could be redeemed on or after April 23, 2003. Interest expense for the years ended December 31, 2003 and 2002 includes $2.9 million and $9.2 million, respectively, of preferred dividends related to the trust preferred capital securities.

As discussed in Note 14, in February 2003, the Company issued $200 million of Notes with a stated interest rate of 5.15% and a maturity date of March 2018. A portion of the proceeds from the issuance were used to redeem the Company s entire $125 million of 7.35% Trust Preferred

Capital Securities on April 23, 2003. No gain or loss was incurred as a result of this redemption.

17. Pension and Other Postretirement Benefit Plans

The Company has defined benefit pension and other postretirement benefit plans covering union members that generally provide benefits of stated amounts for each year of service. Prior to 2003, the Company provided benefits to certain salaried employees through defined benefit plans that used a benefit formula based upon employee compensation. Effective December 31, 2003, the pension benefits provided through this plan were frozen and the covered salaried employees were converted to a defined contribution plan. All other salaried employees are participants in a defined contribution plan. The Company uses a December 31 measurement date for its defined benefit pension and other postretirement plans.

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		Other Benefits	
	2003	2002	2003	2002
	(Thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 112,748	$ 113,666	$ 47,929	$ 46,846
Service cost	2,684	2,557	313	380
Interest cost	7,553	8,101	3,467	3,465
Amendments (a)	144	804		(7,178)
Actuarial loss	9,363	5,731	7,024	9,887
Benefits paid	(7,875)	(8,300)	(5,964)	(5,471)
Expenses paid	(732)	(662)		
Curtailments	(1,007)			
Settlements	(5,931)	(9,149)		
Benefit obligation at end of year	$ 116,947	$ 112,748	$ 52,769	$ 47,929
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 57,116	$ 82,622	$	$ 73
Gain recognized at beginning of year	270			
Actual gain (loss) on plan assets	13,623	(7,395)		(54)
Employer contribution	51,840			
Benefits paid	(7,875)	(8,300)		(19)
Expenses paid	(732)	(662)		
Settlements	(5,931)	(9,149)		
Fair value of plan assets at end of year	$ 108,311	$ 57,116	$	$
Funded status	$ (8,636)	$ (55,632)	$ (52,769)	$ (47,929)
Unrecognized net actuarial loss	38,686	37,702	36,797	32,769
Unrecognized prior service cost (credit)	5,256	8,577	(490)	(532)
Net amount recognized	$ 35,306	$ (9,353)	$ (16,462)	$ (15,692)
Amounts recognized in the statement of financial position consist of:				
Accrued benefit liability	$ (8,636)	$ (55,300)	$ (16,462)	$ (15,692)
Intangible asset	5,256	8,578		
Accumulated other comprehensive loss	25,532	24,663		
Deferred tax asset	13,154	12,706		
Net amount recognized	$ 35,306	$ (9,353)	$ (16,462)	$ (15,692)

(a) The 2002 other postretirement amendment primarily relates to caps placed on the Company s contributions associated with Medicare supplement premiums for retired participants, the adoption of medical spending accounts for active employees that retire after December 31, 2002 and the elimination of postretirement life insurance benefits for non-represented active employees

The pension liability of $8.6 million and $55.3 million as of December 31, 2003 and 2002, respectively, is included in other long-term liabilities. The accrued liability for other postretirement benefits of $16.5 million and $15.7 million as of December 31, 2003 and 2002, respectively, is also included in other long-term liabilities.

The accumulated benefit obligation for all defined benefit pension plans was $116.9 million and $112.4 million at December 31, 2003 and 2002, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $116.9 million, $116.9 million, and $108.3 million, respectively, as of December 31, 2003, and were $112.7 million, $112.4 million, and $57.1 million, respectively, as of December 31, 2002.

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

	Pension Benefits			Other Benefits		
	2003	2002	2001	2003	2002	2001
			(Thousands)			
Components of net periodic benefit cost:						
Service cost	$ 2,684	$ 2,557	$ 2,488	$ 313	$ 380	$ 262
Interest cost	7,553	8,102	8,815	3,467	3,465	3,460
Expected return on plan assets	(8,660)	(9,711)	(11,061)			(205)
Amortization of prior service cost	1,286	1,281	1,677	(42)	(3)	(3)
Amortization of initial net (asset) obligation			(122)		674	683
Recognized net actuarial loss	21	21	16	1,828	1,239	954
Special termination benefits		81	2,394			49
Settlement loss	2,206	3,036	2,016			
Curtailment loss (a)	2,181		209			879
Net periodic benefit cost	$ 7,271	$ 5,367	$ 6,432	$ 5,566	$ 5,755	$ 6,079

(a) The 2003 curtailment loss represents the conversion of approximately 340 salaried employees from the Company s deferred benefit plan to a defined contribution plan.

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	
	2003	2002	2003	2002
Discount rate	6.25%	7.00%	6.25%	7.00%

Expected return on plan assets	8.75%	9.75%	8.75%	9.75%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

The expected rate of return and the rate of compensation increase are established at the beginning of the fiscal year that they relate 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. In determining the expected return on plan assets, 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, Employers Accounting for Pensions. The expected rate of return and the rate of compensation increase determined as of January 1, 2004 totaled 8.25% and 4.50%, respectively. These assumptions will be used to derive the Company s 2004 net periodic benefit cost.

For measurement purposes, the annual rates of increase in the per capita cost of covered health care benefits in 2004 for the Pre-65 and Post-65 medical charges are 8.50% and 10.50%, respectively. The rates were assumed to decrease gradually to ultimate rates of 4.50% in 2008 and 2009, respectively.

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)		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**
Effect on total of service and interest cost components	$ 87	$ 233	$ 210	$ (81)	$ (208)	$ (196)
Effect on postretirement benefit obligation	$ 1,407	$ 1,191	$ 2,505	$ (1,316)	$ (1,114)	$ (2,381)

The Company s pension asset allocation at December 31, 2003 and 2002 and target allocation for 2004 by asset category are as follows:

Asset Category	**Target Allocation 2004**	**Percentage of Plan Assets at December 31, 2003**	**2002**
Domestic broadly diversified equity securities	55%-70%	62%	57%
Fixed income securities	30%-45%	36%	42%
Other	0%-15%	2%	1%
		100%	100%

The investment activities of the Company s pension plan are supervised and monitored by the Benefits Investment Committee. The Company has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the Company 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. Investment managers are retained by the Company to manage separate pools of assets, and funds are allocated to such managers in order to achieve an appropriate, diversified, and balanced asset mix. 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 totaling $51.8 million to its pension plan during the year ended December 31, 2003. The Company does not expect to make a contribution to its defined benefit in 2004.

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. The Company sponsors retiree medical programs for certain of its locations and expects that this legislation will reduce the Company s costs for some of these programs in the future.

In January 2004, FASB Staff Position 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (FSP FAS 106-1) was issued which permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Act. The Company is awaiting guidance from various governmental and regulatory agencies concerning the requirements that must be met to obtain these cost reductions as well as the manner in which such savings should be measured. Based on this preliminary analysis, it appears that some of the Company s retiree medical plans may need to be revised in order to qualify for beneficial treatment under the Act, while other plans can continue unchanged.

Due to various uncertainties related to the Company s response to this legislation and the appropriate accounting methodology for this event, the Company has elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. When issued, that final guidance may require the Company to change previously reported information. In accordance with FSP FAS 106-1, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit cost in the financial statements or accompanying notes do not reflect the effects of the Act on the Company s plan.

Expense recognized by the Company related to its 401(k) employee savings plans totaled $3.1 million in 2003, $3.2 million in 2002 and $2.9 million in 2001.

18. Common Stock and Earnings Per Share

At December 31, 2003, shares of Equitable s authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	9,916
Stock compensation plans	6,597
Total	16,513

Earnings Per Share

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

	Years Ended December 31,		
	2003	2002	2001
	(Thousands, except per share amounts)		
Basic earnings per common share:			
Income from continuing operations before cumulative effect of accounting change	$ 173,557	$ 150,626	$ 151,808
Income from discontinued operations		9,000	
Cumulative effect of accounting change, net of tax	(3,556)	(5,519)	
Net income applicable to common stock	$ 170,001	$ 154,107	$ 151,808
Average common shares outstanding	62,050	62,895	64,347
Basic earnings per common share	$ 2.74	$ 2.45	$ 2.36
Diluted earnings per common share:			
Income from continuing operations before cumulative effect of accounting change	$ 173,557	$ 150,626	$ 151,808
Income from discontinued operations		9,000	

Cumulative effect of accounting change, net of tax		(3,556)		(5,519)		
Net income applicable to common stock	$	170,001	$	154,107	$	151,808
Average common shares outstanding		62,050		62,895		64,347
Potentially dilutive securities:						
Stock options and awards (a)		1,308		1,121		1,728
Total		63,358		64,016		66,075
Diluted earnings per common share	$	2.68	$	2.41	$	2.30

(a) Options to purchase 11,337 shares, 1,217,660 shares and 80,665 shares of common stock were not included in the computation of diluted earnings per common share because the options exercise prices were greater than the average market prices of the common shares for 2003, 2002 and 2001, respectively.

19. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive (loss) income are as follows net of tax:

	2003	2002
	(Thousands)	
Net unrealized (loss) gain from hedging transactions	$ (59,656)	$ 1,617
Unrealized gain (loss) on available-for-sale securities	100,446	(1,494)
Minimum pension liability adjustment	(25,532)	(24,663)
Foreign currency translation adjustment	7	7
	$ 15,265	$ (24,533)

20. Stock-Based Compensation Plans

Long-Term Incentive Plans

The Company s 1994 and 1999 Long-Term Incentive Plans (the Plans) provide for the granting of shares of common stock to officers and key employees of the Company. These grants may be made in the form of stock options, restricted stock, stock appreciation rights and other types of stock-based or performance-based awards as determined by the Compensation Committee of the Board of Directors at the time of each grant. Stock awarded under the Plans, or purchased through the exercise of options, and the value of stock appreciation units are restricted and subject to forfeiture should an optionee terminate employment prior to specified vesting dates. In no case may the number of shares granted under the Plans exceed 3,451,000 and 11,000,000 shares, respectively. Options granted under the Plans expire 6 to 10 years from the date of grant and some contain vesting provisions which are based upon the Company s performance.

Also reflected in the option tables below are options assumed in conjunction with the NORESCO acquisition in July 1997. All outstanding options granted under NORESCO s 1990 Incentive Stock Option Plan were converted by Equitable to nonqualified stock options with the right to receive, upon exercise of the option, the same Equitable stock and cash that shareholders of NORESCO received in the acquisition. As a result of this conversion, 872,000 NORESCO stock options were converted to 512,800 Equitable stock options with the exercise price per share proportionately adjusted. The adjusted exercise prices of these stock options ranged from $2.55 to $2.98 per share. The acquisition also accelerated the vesting period of these options. During 2003, there were no stock options exercised or outstanding under this plan. All options assumed with the NORESCO acquisition have been exercised or expired.

Pro forma information regarding net income and earnings per share for options granted is required by Statement No. 123, and has been determined as if the Company had accounted for its employee stock options under the fair value method of Statement No. 123. The fair value for these option grants was estimated at the dates of grant using a Black-Scholes option-pricing model with the following assumptions for 2003, 2002, and 2001, respectively.

	Years Ended December 31,		
	2003	**2002**	**2001**
Risk-free interest rate (range)	2.35% to 3.72%	3.25% to 5.26%	2.2% to 5.0%
Dividend yield	2.47%	1.96%	1.93%
Volatility factor	.251	.275	.201
Weighted average expected life of options	7 years	7 years	8 years
Options granted	540,915	1,547,146	1,694,821
Weighted average fair market value of options granted during the year	$ 9.68	$ 9.62	$ 9.80

	Years Ended December 31, 2003	2002	2001
Options outstanding January 1	6,166,004	6,068,464	5,204,622
Granted	540,915	1,547,146	1,694,821
Forfeitures	(226,573)	(205,047)	(343,851)
Exercised	(1,592,338)	(1,244,559)	(487,128)
Options outstanding December 31	4,888,008	6,166,004	6,068,464

Options outstanding at December 31, 2003 include 3,125,647 exercisable at that date and are summarized in the following table.

			Options Outstanding				Options Exercisable		
Range of Exercise Prices			Number Outstanding at 12/31/03	Weighted Average Remaining Contractual Life		Weighted Average Fair Value	Exercisable as of 12/31/03		Weighted Average Exercise Price
$ 14.03	to	$ 17.18	760,648	3.4	$	15.27	760,648	$	15.27
$ 17.19	to	$ 21.48	725,530	6.2	$	19.84	725,530	$	19.84
$ 21.49	to	$ 25.78	40,667	5.0	$	24.42	40,667	$	24.42
$ 25.79	to	$ 30.08	294,941	6.9	$	28.98	293,275	$	28.97
$ 30.09	to	$ 34.37	1,177,931	7.2	$	31.53	755,712	$	31.53
$ 34.38	to	$ 38.66	1,787,609	8.3	$	34.96	492,831	$	34.91
$ 38.67	to	$ 42.14	73,049	6.3	$	39.68	56,984	$	39.73

On March 12, 2002, the Company granted 143,000 stock units from the 1999 Long-Term Incentive Plan for the 2002 Executive Performance Incentive Program (2002 Plan). The 2002 Plan was established to provide additional incentive benefits to retain senior executive employees of the Company and to further align the interests of the persons primarily responsible for the success of the Company with the interests of the shareholders. The vesting of these awards will occur on December 31, 2004 and is contingent upon the level of total shareholder return relative to the 30 peer companies identified below and will result in a range of zero to 286,000 shares (200% of the award) being awarded. The Company anticipates, based on current estimates, that the performance measures will be met and has expensed a ratable estimate of the award accordingly. The 2002 Plan expense for the period ended December 31, 2003 was $3.9 million, and is classified as selling, general and administrative expense. Certain amounts were allocated to the Company s operating segments. The stock units are not currently dilutive to the Company s share count as the value of the stock units will be paid in cash or stock, at an employee s election, at the vesting date.

On February 27, 2003, the Company granted 439,400 stock units for the 2003 Executive Performance Incentive Program (2003 Plan). The 2003 Plan was established to provide additional incentive benefits to retain senior executives of the Company and to further align the interests of the persons primarily responsible for the success of the Company with the interests of the shareholders. The vesting of these units will occur on December 31, 2005, contingent upon the level of total shareholder return relative to the 30 peer companies identified below and will result in the distribution of zero to 878,800 units (200% of the units). 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 2003 Plan expense for the year ended December 31, 2003 was $11.1 million and is classified as selling, general and administrative expense. This amount was not allocated to the Company s operating segments. The stock units are not currently dilutive to the Company s share count as the value of the stock units will be paid in cash or stock, at an employee s election, at the vesting date.

Under the 2002 and 2003 Plans, the 30 peer companies may be adjusted by the Compensation Committee of the Company s Board of Directors based on significant or unusual transactions or events that substantially affect the total shareholder return calculation of any company or that, for operational or non-operational reasons, do not reflect or otherwise skew the relevant performance metric intended to be measured. The Company uses different peer groups for other purposes. The current peer companies for the 2002 and 2003 Plans are as follows:

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

In 2003, 2002, and 2001, the Company granted 70,510, 116,300, and 4,000 additional stock awards, respectively, to key executives from the 1999 Long-Term Incentive Plan. The weighted average fair value of these restricted stock grants is $35.59, $32.92, and $36.99, respectively, for 2003, 2002, and 2001. The shares granted under these plans will be fully vested at the end of the three-year period commencing the date of grant. Compensation expense recorded by the Company related to stock awards was $2.6 million in 2003, $3.2 million in 2002, and $2.3 million in 2001.

Nonemployee Directors Stock Incentive Plans

The Company s 1994 and 1999 Nonemployee Directors Stock Incentive Plans provide for the granting of up to 160,000 and 600,000 shares, respectively, of common stock in the form of stock option grants and restricted stock awards to nonemployee directors of the Company. The exercise price for each share is equal to market price of the 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. At December 31, 2003, 163,200 options were outstanding under the 1999 Nonemployee Directors Stock Incentive Plan at prices ranging from $12.89 to $42.96 per share, and 181,000 options had been exercised under these plans since the plan inception. During 2003, no options were outstanding or exercisable under the 1994 Nonemployee Directors Stock Incentive Plan.

21. 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 14 at December 31, 2003 and 2002 was $696.9 million and $521.8 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 commodity instruments described in Note 3, excluding trading activities which are marked-to-market, was a $34.5 million asset and a $137.6 million liability at December 31, 2003 and a $30.9 million asset and a $25.0 million liability at December 31, 2002.

22. 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 to certain marketers, Equitable Energy, 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, Ohio, Pennsylvania and West Virginia.

The Equitable Utilities Distribution operating revenues and related accounts receivable are generated from state-regulated utility natural gas sales and transportation to more than 274,500 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, as well as other utility and end-user customers located in the northeastern United States. The unregulated Marketing operation provides commodity procurement and delivery, physical natural gas management operations and control, and customer support services to energy consumers including large industrial, utility, commercial, institutional and certain marketers primarily in the Appalachian and mid-Atlantic regions. Under state regulations, the Utility is required to provide continuous natural gas service to residential customers during the winter heating season.

Approximately 45% and 40% of the Company s accounts receivable balance as of December 31, 2003 and 2002, respectively, represents 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, 2003, and 2002.

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.

The NORESCO segment s operating revenues and related accounts receivable are generated from performance contracts with federal, state, and local government, institutional customers throughout the United States and cogeneration and power plant facilities in several U.S. and Latin American markets.

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

23. Commitments and Contingencies

The Company has annual commitments of approximately $24.5 million for demand charges under existing long-term contracts with pipeline suppliers for periods extending up to nine years as of December 31, 2003, which relate to natural gas distribution and production operations. However, approximately $19.5 million of these costs are recoverable in customer rates.

In the third quarter of 2003, the Company signed a long-term lease for office space with Continental Real Estate Companies, which will own and construct the building in which the office space will be located. Plans call for the building to be complete in late 2004 or early 2005. The term of the lease is 20 years and nine months and the base rent is approximately $2 million per year. The office space is located at the North Shore in Pittsburgh, Pennsylvania and will allow Equitable to consolidate its Pittsburgh office operations and increase efficiencies. Relocation of operations from locations that utilize space under long-term leases will likely cause additional expense late in 2004 and 2005.

There are various claims and legal proceedings against the Company arising from the normal course of business. Although counsel is unable to predict with certainty the ultimate outcome, management and counsel believe that the Company has significant and meritorious defenses to any claims and intends to pursue them vigorously. Management has provided adequate reserves and therefore believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the financial position of the Company. The reserves recorded by the Company do not include any amounts for legal costs expected to be incurred. It is the Company s policy to recognize any legal costs associated with any claims and legal proceedings against the Company s continuing operations as they are incurred.

After an extended period of troubled operations, ERI JAM, LLC, a subsidiary that holds the Company s interest in EAL/ERI Cogeneration Partners LP, an international infrastructure project, filed for bankruptcy protection under Chapter 11 in U.S. Bankruptcy Court (Delaware) in April 2003. In the third quarter 2003, ERI JAM, LLC transferred control of the international infrastructure project under the partnership agreement to the other general partner. The international infrastructure project was deconsolidated in accordance with FIN No. 46 (see Note 1). In September 2003, project-level counterparties, Jamaica Broilers Group Limited (JBG) and Energy Associated Limited (EAL), filed a claim against ERI JAM LLC as Debtor-in-Possession in the Chapter 11 case. EAL is a limited partner in EAL/ERI Cogeneration Partners LP. In October 2003, JBG and EAL also filed a multi-count complaint against Equitable and certain of its affiliates in U.S. District Court (Western District of PA). Equitable and its affiliates intend to vigorously defend this litigation, which they view as without merit. Resolution within the Chapter 11 proceedings pursuant to a global settlement is sought.

The various regulatory authorities that oversee Equitable s operations will, from time to time, make inquiries or investigations into the activities of the Company. The Company has received informal requests for information from the Commodity Futures Trading Commission (CFTC) regarding the reporting of prices to industry publications during 2001, 2002 and 2003. The Company has cooperated fully with the CFTC in this matter as the Company always does when regulatory bodies make requests. The Company has investigated this matter thoroughly internally and uncovered no evidence to date that any of its employees ever intentionally reported any false information to any industry publication.

In July 2002, the United States Environmental Protection Agency (EPA) published a final rule that amends the Oil Pollution Prevention Regulation. The effective date of the rule was August 16, 2002. Under the final rule, Owners/Operators of existing facilities were to revise their Spill Prevention, Control and Countermeasure (SPCC) plans on or before February 17, 2003 and were required to implement the amended plans as soon as possible but not later than August 18, 2003. On April 17, 2003, the EPA extended the deadline to adopt a plan amendment to August 17, 2004 and the deadline to comply with the amended plan to February 18, 2005. There is currently active litigation regarding the final rule and management anticipates that the regulation will be modified. Nonetheless the Company is studying, and is preparing to implement, its plan of compliance. The ultimate outcome of the pending litigation and any regulatory modification may affect the Company s ability to timely comply and will affect the total costs of compliance, currently expected to be $18.0 million, approximately two-thirds of which are expected to be capitalized.

In addition to the SPCC, the Company is subject to other 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.

Any estimated costs associated with identified situations that require remedial action are accrued with certain costs deferred as regulatory assets, as applicable. The Company has identified situations that require remedial action for which approximately $4.4 million is included in other long-term liabilities at December 31, 2003.

At the end of the useful life of a well the Company is required to remediate the site by plugging and abandoning the well. Costs associated with this obligation totaled $1.3 million, $0.7 million and $0.8 million during the years ended December 31, 2003, 2002 and 2001, respectively.

Operating lease rentals for office locations and warehouse buildings, as well as a limited amount of equipment amounted to approximately $5.5 million in 2003, $5.8 million in 2002 and $6.9 million in 2001. Future

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lease payments under non-cancelable operating leases as of December 31, 2003 totaled $69.6 million (2004 - $6.7 million, 2005 - $6.2 million, 2006 - $6.4 million, 2007 - $5.7 million, 2008 - $4.7 million and thereafter - $39.9 million).

24. Guarantees

In November 1995, the Company monetized Appalachian gas properties to a partnership, ABP, the production from which qualified for nonconventional fuels tax credits. As part of that transaction, Equitable, through a subsidiary guaranteed a tax indemnification to the limited partners 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 periods ending December 31, 1997 are closed. As of December 31, 2003, the maximum potential amount of future payments the Company could be required to make is estimated to be approximately $46.0 million. As of December 31, 2003, the Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN No. 45 and has not been modified subsequent to issuance. 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 any of the amounts paid under the guarantee.

In June 2000, Equitable sold properties with reserves of approximately 66.0 Bcfe, the production from which qualified for nonconventional fuels tax credits. As part of that transaction, Equitable, 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 closes. As of December 31, 2003, the maximum potential amount of future payments the Company could be required to make is estimated to be approximately $23.0 million. As of December 31, 2003, the Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN No. 45 and has not been modified subsequent to issuance.

In December 2000, the Company entered into a transaction with Appalachian Natural Gas Trust (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. 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 and limitations, as set forth in the guarantee agreement, as to the eligibility, amount and terms of the guarantee. These restrictions 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, 2003, the maximum potential amount of future payments the Company could be required to make under the liquidity reserve guarantee is estimated to be $29.0 million. As of December 31, 2003, the Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN No. 45 and has not been modified subsequent to issuance.

A wholly owned subsidiary of the Company has provided two guarantees in the total amount of $5.4 million in support of a 50% owned non-recourse financed energy project located in Panama. The guarantees represent 50% of the performance guaranty for the project s principal Power Purchase Agreement and cover a project loan debt service reserve requirement. As of December 31, 2003, the Company has not recorded a liability for this guarantee, as the guarantee was issued prior to the effective date of FIN No. 45 and has not been modified subsequent to issuance.

25. 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:

	March 31	June 30	September 30	December 31
		(Thousands except per share amounts)		
2003				
Operating revenues	$ 342,322	$ 218,496	$ 185,515	$ 300,944
Net operating revenues	188,352	132,070	128,426	169,723
Operating income	109,320	56,817	54,177	81,903
Income from continuing operations before cumulative effect of accounting change	64,479	31,395	28,212	49,471
Net income (a)	60,923	31,395	28,212	49,471
Earnings per share:				
Income from continuing operations before cumulative effect of accounting change				
Basic	$ 1.04	$ 0.51	$ 0.45	$ 0.80
Diluted	$ 1.02	$ 0.50	$ 0.45	$ 0.78
Net Income				
Basic	$ 0.98	$ 0.51	$ 0.45	$ 0.80
Diluted	$ 0.96	$ 0.50	$ 0.45	$ 0.78
2002				
Operating revenues	$ 294,043	$ 226,671	$ 214,418	$ 333,936
Net operating revenues	160,876	124,018	118,367	159,444
Operating income	94,218	54,033	50,875	78,445
Income from continuing operations before cumulative effect of accounting change	52,372	29,189	26,686	42,379
Net income (a)	46,853	38,189	26,686	42,379
Earnings per share:				
Income from continuing operations before cumulative effect of accounting change				
Basic	$ 0.82	$ 0.46	$ 0.43	$ 0.68
Diluted	$ 0.80	$ 0.45	$ 0.42	$ 0.67
Net Income				
Basic	$ 0.74	$ 0.60	$ 0.43	$ 0.68
Diluted	$ 0.72	$ 0.59	$ 0.42	$ 0.67

(a) Net Income for the period ended March 31, 2003 includes the negative cumulative effect of an accounting change related to the adoption of Statement No. 143. Net income for the period ended March 31, 2002 has been adjusted to reflect the negative cumulative effect of accounting change related to the adoption of Statement No. 142 that was retroactive to the first quarter 2002. In addition, net income for the period ended June 30, 2002 includes $9.0 million from income from discontinued operations.

26. Natural Gas Producing Activities (Unaudited)

The supplementary information summarized below presents the results of natural gas and oil activities for the Equitable Supply segment in accordance with SFAS No. 69, Disclosures About Oil and Natural Gas Producing Activities.

Production Costs

The following table presents the costs incurred relating to natural gas and oil production activities:

	2003	2002	2001
		(Thousands)	
At December 31:			
Capitalized costs	$ 1,303,655	$ 1,140,129	$ 1,022,834
Accumulated depreciation and depletion	450,761	406,399	410,429
Net capitalized costs	$ 852,894	$ 733,730	$ 612,405
Costs incurred:			
Property acquisition:			
Proved properties	$	$	$
Unproved properties			
Land and leasehold maintenance	824	847	2,005
Development (a)	125,962	114,341	83,139

(a) Amounts include $82.7 million, $82.5 million, and $58.2 million of costs incurred during 2003, 2002 and 2001, respectively, to develop the Company s proved undeveloped reserves. The Company estimates that its future total development costs will be comprised of a similar percentage of costs incurred to develop the Company s proved undeveloped reserves.

Results of Operations for Producing Activities

The following table presents the results of operations related to natural gas and oil production:

	2003	2002	2001
		(Thousands)	
Revenues:			
Affiliated	$ 11,457	$ 7,145	$ 3,938
Nonaffiliated	251,150	218,568	236,742
Production costs	34,863	26,264	32,495
Land and leasehold maintenance expenses	824	847	2,005
Depreciation and depletion	35,974	28,387	28,465
Income tax expense	71,414	52,076	62,218
Results of operations from producing activities (excluding corporate overhead)	$ 119,532	$ 118,139	$ 115,497

Reserve Information

The information presented below represents estimates of proved natural gas and oil reserves prepared by Company engineers, which was reviewed by the independent consulting firm of Ryder Scott Company LP. Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells after substantial development costs are incurred. All of the Company s proved reserves are in the United States.

In December 2001, the Company sold reserves associated with its Kentucky oil fields totaling 68 Bcfe. In February 2003, the Company sold approximately 500 of its low-producing wells, within two of its non-strategic districts in two separate transactions. The sales resulted in a decrease of 13 Bcfe of net reserves. The 500 wells produced an aggregate of approximately 1.0 Bcfe in 2002. Additionally, in February 2003, the Company purchased the remaining 31% limited partnership interest in ABP from the minority interest holders for $44.2 million. These reserves were already incorporated into the 2002 and 2001 reserve amounts.

	2003	2002	2001
		(Millions of Cubic Feet)	
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	2,131,821	2,072,871	2,164,630
Revision of previous estimates	(41,053)	44,099	(75,476)
Sale of natural gas in place	(7,146)		(39,990)
Extensions, discoveries and other additions (a)	49,926	82,022	88,413
Production	(69,422)	(67,171)	(64,706)
End of year	2,064,126	2,131,821	2,072,871
Proved developed reserves:			
Beginning of year	1,573,278	1,490,093	1,563,076
End of year	1,580,474	1,573,278	1,490,093

	2003	2002	2001
		(Thousands of Barrels)	
Oil			
Proved developed and undeveloped reserves:			
Beginning of year	1,432	1,563	6,867
Revision of previous estimates	170	(4)	(191)
Sale of oil in place	(969)		(4,662)
Production	(83)	(127)	(451)
End of year	550	1,432	1,563
Proved developed reserves:			
Beginning of year	1,432	1,563	6,867
End of year	550	1,432	1,563

(a) Includes 31,755 MMcf, 21,300 MMcf, and 26,973 MMcf of proved developed reserve extensions, discoveries and other additions during 2003, 2002 and 2001, respectively, that were not previously classified as proved undeveloped. The remaining balance represents additional proved undeveloped reserves.

Standard Measure of Discounted Future Cash Flow

Management cautions that the standard measure of discounted future cash flows should not be viewed as an indication of the fair market value of natural gas and oil producing properties, nor of the future cash flows expected to be generated therefrom. The information presented does not give recognition to future changes in estimated reserves, selling prices or costs and has been discounted at an arbitrary rate of 10%. Estimated future net cash flows from natural gas and oil reserves based on selling prices and costs at year-end price levels are as follows:

	2003	2002	2001
		(Thousands)	
Future cash inflows	$ 10,462,523	$ 9,180,390	$ 5,966,131
Future production costs	(1,938,827)	(1,529,713)	(1,242,227)
Future development costs	(341,116)	(381,667)	(348,978)
Future net cash flow before income taxes	8,182,580	7,269,010	4,374,926
10% annual discount for estimated timing of cash flows	(5,550,907)	(5,037,625)	(3,066,798)
Discounted future net cash flows before income taxes	2,631,673	2,231,385	1,308,128
Future income tax expenses, discounted at 10% annually	(921,086)	(780,985)	(457,845)
Standardized measure of discounted future net cash flows	$ 1,710,587	$ 1,450,400	$ 850,283

Summary of changes in the standardized measure of discounted future net cash flows:

	2003	2002	2001
		(Thousands)	
Sales and transfers of natural gas and oil produced net	$ (227,745)	$ (199,449)	$ (206,675)
Net changes in prices, production and development costs	413,043	720,238	(5,426,615)
Extensions, discoveries and improved recovery, less related costs	63,645	85,508	55,544
Estimated future development costs	70,112	69,267	61,667
Sale of minerals in place net	(12,659)		(138,274)
Revisions of previous quantity estimates	(111,228)	103,734	(48,136)
Accretion of discount	221,873	130,813	632,593
Net change in income taxes	(140,101)	(323,140)	1,936,509
Other	(16,753)	13,146	(93,202)
Net increase (decrease)	260,187	600,117	(3,226,589)
Beginning of year	1,450,400	850,283	4,076,872
End of year	$ 1,710,587	$ 1,450,400	$ 850,283

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

Not Applicable.

Item 9A **Controls and Procedures**

The Chief Executive Officer and Chief Financial Officer conducted an evaluation of the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of the end of the period covered by this report. There were no significant changes in internal control over financial reporting (as defined in Rule 13a-15f under the Exchange Act) that occurred during the fourth quarter of 2003 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART III

Item 10. **Directors and Executive Officers of the Registrant**

The following information is incorporated herein by reference from the Company s definitive proxy statement related to the annual meeting of the shareholders to be held on April 14, 2004, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2003:

Information required by Item 401 of Regulation S-K with respect to directors is incorporated herein by reference from the section captioned Item No. 1 - Election of Directors in the Company s definitive proxy statement;

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

The information required by Item 401 of Regulation S-K with respect to disclosure of audit committee financial experts is incorporated herein by reference from the section captioned Report of the Audit Committee in the Company s definitive proxy statement; and

The information required by Item 401 of Regulation S-K with respect to the identification of the Audit Committee is incorporated by reference from the section captioned Corporate Governance Committees of the Board in the Company s definitive proxy statement.

Information required by Item 401 of Regulation S-K with respect to executive officers is included herein after Item 4 at the end of Part I of Form 10-K under the heading Executive Officers of the Registrant (as of March 1, 2004), and is incorporated herein by reference.

The Company has adopted a code of ethics applicable to all directors and employees, including the principal executive officer, principal financial officer and principal accounting officer. The code of ethics is posted on the Company s website, www.eqt.com (under the Corporate Governance caption of the Investor Relations page) and a printed copy will be delivered to anyone who so requests by writing to the corporate secretary at Equitable Resources, Inc., c/o corporate secretary, One Oxford Centre, 301 Grant Street, Suite 3300, Pittsburgh, Pennsylvania 15219. The Company intends to satisfy the disclosure requirement regarding certain amendments to, or waivers from, provisions of its code of ethics by posting such information on the Company s website. The Company s corporate governance guidelines and the charters of the Audit Committee, the Compensation Committee and the Corporate Governance Committee of the Board of Directors are also available on the Company s website, www.eqt.com (under the Corporate Governance caption of the Investor Relations page) and a printed copy will be delivered to anyone who so requests by writing to the corporate secretary at Equitable Resources, Inc., c/o corporate secretary, One Oxford Centre, 301 Grant Street, Suite 3300, Pittsburgh, Pennsylvania 15219.

Item 11. Executive Compensation

Information required by Item 11 is incorporated herein by reference from the sections describing Executive Compensation in the Company s definitive proxy statement relating to the annual meeting of stockholders to be held on April 14, 2004, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2003.

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

Information required by Item 12 is incorporated herein by reference to the section describing Equity Compensation Plans in the Company s definitive proxy statement relating to the annual meeting of stockholders to be held on April 14, 2004, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2003.

Item 13. Certain Relationships and Related Transactions

None.

Item 14. Principal Accountant Fees and Services

Information required by Item 14 is incorporated herein by reference to the section describing Ratification of Appointment of Auditors in the Company s definitive proxy statement relating to the annual meeting of stockholders to be held on April 14, 2004, which will be filed with the Commission within 120 days after the close of the Company s fiscal year ended December 31, 2003.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) 1. Financial Statements

The financial statements listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

2. Financial Statement Schedule

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

3. Exhibits

The exhibits listed on the accompanying index to exhibits (pages 109 through 114) are filed as part of this Annual Report on Form 10-K.

(b) Reports on Form 8-K filed during the quarter ended December 31, 2003.

(i) Form 8-K dated October 17, 2003 disclosing the Company s issuance of a press release announcing the results of its third quarter 2003 earnings.

(ii) Form 8-K dated December 15, 2003 disclosing the Company s addition of a Corporate Governance section to the Company s website and the announcement of the date of the 2004 Annual Meeting of Shareholders.

EQUITABLE RESOURCES, INC.

INDEX TO FINANCIAL STATEMENTS COVERED

BY REPORT OF INDEPENDENT AUDITORS

(Item 15 (a))

1. The following consolidated financial statements of Equitable Resources, Inc. and Subsidiaries are included in Item 8:

Statements of Consolidated Income for each of the three years in the period ended
December 31, 2003

Statements of Consolidated Cash Flows for each of the three years in the period ended
December 31, 2003

Consolidated Balance Sheets as of December 31, 2003 and 2002

Statements of Common Stockholders Equity for each of the three years in the period ended
December 31, 2003

Notes to Consolidated Financial Statements

2. Schedule for the Years Ended December 31, 2003, 2002 and 2001 included in Part IV:
II Valuation and Qualifying Accounts and Reserves

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

EQUITABLE RESOURCES, INC. AND SUBSIDIARIES
SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2003

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Acquisitions	Deductions (b)	Balance at End of Period
			(Thousands)		
2003					
Accumulated provisions for doubtful accounts	$ 15,294	$ 13,697		$ 10,950	$ 18,041
2002					
Accumulated provisions for doubtful accounts	$ 14,807	$ 8,564		$ 8,077	$ 15,294
2001					
Accumulated provisions for doubtful accounts	$ 15,413	$ 14,866(a)		$ 15,472(a)	$ 14,807

Note:

(a) Excludes the $23.4 million accounts receivable special arrears receivables that were written-off directly and a regulatory asset was created for its recovery in rates. See Note 11 within Item 8 for further discussion of the Company s regulatory assets.

(b) Customer accounts written off, less recoveries.

INDEX TO EXHIBITS

Exhibits	Description	Method of Filing
3.01	Restated Articles of Incorporation of the Company dated May 1, 2001	Filed as Exhibit 3.01 to Form 10-K for the year-ended December 31, 2002
3.02	Bylaws of the Company (amended through May 17, 2001)	Filed as Exhibit 3.02 to Form 10-K for the year-ended December 31, 2002
4.01 (a)	Indenture dated as of April 1, 1983 between the Company and Pittsburgh National Bank	Filed as 4.1 to Registration Statement on From S-3 filed April 24, 1986 (Registration No. 2-80575)
4.01 (b)	Instrument appointing Bankers Trust Company as successor trustee to Pittsburgh National Bank	Filed as Exhibit 4.01 (b) to Form 10-K for the year ended December 31, 1998
4.01 (c)	Resolutions adopted June 22, 1987 by the Finance Committee of the Board of Directors of the Company establishing the terms of the 75,000 units (debentures with warrants) issued July 1, 1987	Filed as Exhibit 4.01 (c) to Form 10-K for the year ended December 31, 1998
4.01 (d)	Supplemental Indenture dated March 15, 1991 with Bankers Trust Company eliminating limitations on liens and additional funded debt	Filed as Exhibit 4.01 (f) to Form 10-K for the year ended December 31, 1996
4.01 (e)	Resolution adopted August 19, 1991 by the Ad Hoc Finance Committee of the Board of Directors of the Company Addenda Nos. 1 through 27, establishing the terms and provisions of the Series A Medium-Term Notes	Filed as Exhibit 4.01 (g) to Form 10-K for the year ended December 31, 1996
4.01 (f)	Resolutions adopted July 6, 1992 and February 19, 1993 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 8, establishing the terms and provisions of the Series B Medium-Term Notes	Refiled as Exhibit 4.01 (h) to Form 10-K for the year ended December 31, 1997
4.01 (g)	Resolution adopted July 14, 1994 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 and 2, establishing the terms and provisions of the Series C Medium-Term Notes	Filed as Exhibit 4.01 (i) to Form 10-K for the year ended December 31, 1995
4.02 (a)	Indenture with The Bank of New York, as successor to Bank of Montreal Trust Company, a Trustee, dated as of July 1, 1996	Filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2003

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

Exhibits	Description	Method of Filing
4.02 (b)	Resolution adopted January 18 and July 18, 1996 by the Board of Directors of the Company and Resolutions adopted July 18, 1996 by the Executive Committee of the Board of Directors of the Company, establishing the terms and provisions of the 7.75% Debentures issued July 29, 1996	Filed as Exhibit 4.01 (j) to Form 10-K for the year ended December 31, 1996
4.02 (c)	Resolutions adopted January 16, 2003 by the Board of Directors establishing the terms of the offering of up to $200,000,000 aggregate principal amount of 5.15% Notes due 2018	Filed as Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 2003
4.02 (d)	Officer s Declaration dated February 20, 2003 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of up to $200,000,000	Filed as Exhibit 10.5 to Form 10-Q for the quarter ended June 30, 2003
4.02 (e)	Officer s Certificate dated February 27, 2003 certifying the terms and form of the Notes in an aggregate amount of up to $200,000,000	Filed as Exhibit 10.6 to Form 10-Q for the quarter ended June 30, 2003
4.02 (f)	Resolutions adopted October 17, 2002 by the Board of Directors establishing the terms of the offering of up to $200,000,000 aggregate principal amount of 5.15% Notes Due 2012	Filed as Exhibit 10.7 to Form 10-Q for the quarter ended June 30, 2003
4.02 (g)	Officer s Certificate dated November 7, 2002 establishing the terms of the issuance and sale of the Notes of the Company in an aggregate amount of up to $200,000,000	Filed as Exhibit 10.8 to Form 10-Q for the quarter ended June 30, 2003
4.02 (h)	Officer s Certificate dated November 15, 2002 certifying the terms and form of the Notes in an aggregate amount of up to $200,000,000	Filed as Exhibit 10.9 to Form 10-Q for the quarter ended June 30, 2003
4.03	Amended and Restated Rights Agreement dated as of January 23, 2004 between the Company and Mellon Investor Services, L.L.C., setting forth the amended and restated terms of the Company s Preferred Stock Purchase Rights Plan	Filed as Exhibit 1 to Registration Statement on Form 8-A/A filed January 29, 2004
10.01	Equitable Resources, Inc. $500,000,000 Revolving Credit Agreement dated October 30, 2003	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2003
* 10.02	1999 Equitable Resources, Inc. Long-Term Incentive Plan (amended and restated May 18, 2001)	Filed as Exhibit 10.38 to Form 10-Q for the quarter ended September 30, 2002

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

Exhibits	Description	Method of Filing
* 10.03	1994 Equitable Resources, Inc Long-Term Incentive Plan	Refiled as Exhibit 10.06 to Form 10-K for the year ended December 31, 1999
* 10.04	Equitable Resources, Inc. Breakthrough Long-Term Incentive Plan with certain executives of the Company (as amended through November 30, 1999)	Filed as Exhibit 10.01 to Form 10-Q for the quarter ended September 30, 2000
* 10.05	1999 Equitable Resources, Inc. Non-Employee Directors Stock Incentive Plan (as amended May 26, 1999)	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 1999
* 10.06	Equitable Resources, Inc. Executive Short-Term Incentive Plan	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2001
* 10.07	Equitable Resources, Inc. 2002 Short-Term Incentive Plan	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2002
* 10.08	Equitable Resources, Inc. 2003 Short-Term Incentive Plan	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2003
* 10.09	Equitable Resources, Inc. 2002 Executive Performance Incentive Program (as amended and restated May 1, 2003)	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2003
* 10.10	Equitable Resources, Inc. 2003 Executive Performance Incentive Program	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2003
* 10.11	Equitable Resources, Inc. Directors Deferred Compensation Plan (as amended and restated May 15, 2003)	Filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2003
* 10.12	Equitable Resources, Inc. Employee Deferred Compensation Plan (amended and restated effective December 3, 2003)	Filed herewith as Exhibit 10.12
* 10.13 (a)	Employment Agreement dated as of May 4, 1998 with Murry S. Gerber	Filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 1998
* 10.13 (b)	Amendment No. 1 to Employment Agreement with Murry S. Gerber	Filed as Exhibit 10.09 (b) to Form 10-K for the year ended December 31, 1999
* 10.13 (c)	Amendment No. 2 to Employment Agreement with Murry S. Gerber	Filed as Exhibit 10.09 (c) to Form 10-Q for the quarter ended September 30, 2002
* 10.13 (d)	Amendment No. 3 to Employment Agreement with Murry S. Gerber	Filed herewith as Exhibit 10.13 (d)
* 10.13 (e)	Change in Control Agreement dated September 1, 2002 by and between Equitable Resources, Inc. and Murry S. Gerber	Filed as Exhibit 10.10 to Form 10-Q for the quarter ended September 30, 2002
* 10.13 (f)	Supplemental Executive Retirement Agreement dated as of May 4, 1998 with Murry S. Gerber	Filed as Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 1998

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

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Exhibits	Description	Method of Filing
* 10.13 (g)	Amended and Restated Post-Termination Confidentiality and Non-Competition Agreement dated December 1, 1999 with Murry S. Gerber	Filed as Exhibit 10.12 to Form 10-K for the year ended December 31, 1999
* 10.14 (a)	Employment Agreement dated as of July 1, 1998 with David L. Porges	Filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 1998
* 10.14 (b)	Amendment No. 1 to Employment Agreement with David L. Porges	Filed as Exhibit 10.13 (b) to Form 10-K for the year ended December 31, 1999
* 10.14 (c)	Amendment No. 2 to Employment Agreement with David L. Porges	Filed as Exhibit 10.13 (c) to Form 10-Q for the quarter ended September 30, 2002
* 10.14 (d)	Amendment No. 3 to Employment Agreement with David L. Porges	Filed herewith as Exhibit 10.14 (d)
* 10.14 (e)	Change in Control Agreement dated September 1, 2002 by and between Equitable Resources, Inc. and David L. Porges	Filed as Exhibit 10.14 to Form 10-Q for the quarter ended September 30, 2002
* 10.14 (f)	Amended and Restated Post-Termination Confidentiality and Non-Competition Agreement dated December 1, 1999 with David L. Porges	Filed as Exhibit 10.15 to Form 10-K for the year ended December 31, 1999
* 10.15 (a)	Change in Control Agreement dated September 1, 2002 by and between Equitable Resources, Inc. and Johanna G. O Loughlin	Filed as Exhibit 10.18 to Form 10-Q for the quarter ended September 30, 2002
* 10.15 (b)	Noncompete Agreement dated December 1, 1999 with Johanna G. O Loughlin	Filed as Exhibit 10.19 to Form 10-K for the year ended December 31, 1999
* 10.15 (c)	Release re: Split Dollar	Filed herewith as Exhibit 10.15 (c)
* 10.16 (a)	Agreement dated May 24, 1996 with Phyllis A. Domm for deferred payment of 1996 director fees beginning May 24, 1996	Filed as Exhibit 10.14 (a) to Form 10-K for the year ended December 31, 1996
* 10.16 (b)	Agreement dated November 27, 1996 with Phyllis A. Domm for deferred payment of 1997 director fees	Filed as Exhibit 10.14 (b) to Form 10-K for the year ended December 31, 1996
* 10.16 (c)	Agreement dated November 30, 1997 with Phyllis A. Domm for deferred payment of 1998 director fees	Filed as Exhibit 10.14 (c) to Form 10-K for the year ended December 31, 1997
* 10.16 (d)	Agreement dated December 5, 1998 with Phyllis A. Domm for deferred payment of 1999 director fees	Filed as Exhibit 10.20 (d) to Form 10-K for the year ended December 31, 1998
* 10.17 (a)	Indemnification Agreement dated January 18, 2001 by and between Equitable Resources, Inc. and Joseph E. O Brien	Filed as Exhibit 10.30 to Form 10-K for the year ended December 31, 2000

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

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Exhibits	Description	Method of Filing
* 10.17 (b)	Change of Control Agreement dated September 1, 2002 by and between Equitable Resources, Inc. and Joseph E. O Brien	Filed as Exhibit 10.31 to Form 10-Q for the quarter ended September 30, 2002
* 10.17 (c)	Noncompete Agreement dated January 30, 2001 by and between Equitable Resources, Inc. and Joseph E. O Brien	Filed as Exhibit 10.32 to Form 10-K for the year ended December 31, 2000
* 10.18 (a)	Indemnification Agreement dated January 1, 2003 by and between Equitable Resources, Inc. and Randall L. Crawford	Filed herewith as Exhibit 10.18 (a)
* 10.18 (b)	Change of Control Agreement dated December 1, 1999 by and between Equitable Resources, Inc. and Randall L. Crawford	Filed herewith as Exhibit 10.18 (b)
* 10.18 (c)	Noncompete Agreement dated December 1, 1999 by and between Equitable Resources, Inc. and Randall L. Crawford	Filed herewith as Exhibit 10.18 (c)
* 10.19	Form of Indemnification Agreement between Equitable Resources, Inc. and certain executive officers and outside directors	Filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2002
10.20	Registration Rights Agreement by and among Westport Resources Corporation, ERI Investments, Inc., Westport Energy, LLC, Medicor Foundation and certain shareholders named therein dated as of October 1, 2003	Filed as Exhibit 10.2 to Amendment No. 2 to Schedule 13D dated October 21, 2003
10.21	Termination and Voting Agreement, dated as of October 1, 2003, by and among Westport Resources Corporation, Westport Energy LLC, ERI Investments, Inc., Medicor Foundation and certain other persons named therein	Filed as Exhibit 10.1 to Amendment No. 2 to Schedule 13D dated October 21, 2003
21	Schedule of Subsidiaries	Filed herewith as Exhibit 21
23.01	Consent of Independent Auditors	Filed herewith as Exhibit 23.01
23.02	Consent of Independent Petroleum Engineers	Filed herewith as Exhibit 23.02
31.1	Certification of Murry S. Gerber, Chief Executive Officer of Equitable Resources, Inc., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31.1
31.2	Certification of David L. Porges, Chief Financial Officer of Equitable Resources, Inc., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31.2

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

Exhibits	Description	Method of Filing
32	Certification of Murry S. Gerber, Chief Executive Officer of Equitable Resources, Inc., and David L. Porges, Chief Financial Officer of Equitable Resources, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EQUITABLE RESOURCES, INC.

By: /s/ Murry S. Gerber
Murry S. Gerber
Chairman, President and Chief Executive Officer
February 25, 2004

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ MURRY S. GERBER Murry S. Gerber (Principal Executive Officer)	Chairman, President and Chief Executive Officer	February 25, 2004
/s/ DAVID L. PORGES David L. Porges (Principal Financial Officer)	Executive Vice President and Chief Financial Officer	February 25, 2004
/s/ JOHN A. BERGONZI John A. Bergonzi (Principal Accounting Officer)	Vice President and Corporate Controller	February 25, 2004
/s/ PHYLLIS A. DOMM Phyllis A. Domm	Director	February 25, 2004
/s/ BARBARA S. JEREMIAH Barbara S. Jeremiah	Director	February 25, 2004
/s/ THOMAS A. McCONOMY Thomas A. McConomy	Director	February 25, 2004
/s/ GEORGE L. MILES, JR. George L. Miles, Jr.	Director	February 25, 2004
/s/ JAMES E. ROHR James E. Rohr	Director	February 25, 2004
/s/ DAVID S. SHAPIRA	Director	February 25, 2004

David S. Shapira		
/s/ LEE T. TODD, Jr. Lee T. Todd, Jr.	Director	February 25, 2004
/s/ JAMES W. WHALEN James W. Whalen	Director	February 25, 2004