UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(MARK ONE)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM   TO

COMMISSION FILE NUMBER 1-13265

CENTERPOINT ENERGY RESOURCES CORP.
(Exact name of registrant as specified in its charter)

DELAWARE (State or other jurisdiction of incorporation or organization)	76-0511406 (I.R.S. Employer Identification Number)
1111 LOUISIANA HOUSTON, TEXAS 77002 (Address and zip code of principal executive offices)	(713) 207-1111 (Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
NorAm Financing I 6 1/4% Convertible Trust Originated Preferred Securities	New York Stock Exchange
6% Convertible Subordinated Debentures due 2012	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
NONE

CENTERPOINT ENERGY RESOURCES CORP. MEETS THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K AND IS THEREFORE FILING THIS FORM 10-K WITH THE REDUCED DISCLOSURE FORMAT.

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

Indicate by check mark 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 the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined by Rule 12b-2 of the Act). Yes [ ] No [X]

The aggregate market value of the common equity held by non-affiliates as of June 30, 2004: None

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We meet the conditions specified in General Instruction I(1)(a) and (b) of Form 10-K and are thereby permitted to use the reduced disclosure format for wholly owned subsidiaries of reporting companies specified therein. Accordingly, we have omitted from this report the information called for by Item 4 (Submission of Matters to a Vote of Security Holders), Item 10 (Directors and Executive Officers of the Registrant), Item 11 (Executive Compensation), Item 12 (Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters) and Item 13 (Certain Relationships and Related Transactions) of Form 10-K. In lieu of the information called for by Item 6 (Selected Financial Data) and Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) of Form 10-K, we have included under Item 7 a Management's Narrative Analysis of the Results of Operations to explain the reasons for material changes in the amount of revenue and expense items between 2002, 2003 and 2004.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from those expressed or implied by these statements. You can generally identify our forward-looking statements by the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "should," "will," or other similar words.

We have based our forward-looking statements on our management's beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied by our forward-looking statements are described under "Risk Factors" beginning on page 11 in Item 1 of this report.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements.

PART I

ITEM 1. BUSINESS

OUR BUSINESS

GENERAL

We own gas distribution systems serving approximately 3 million customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. Through wholly owned subsidiaries, we also own two interstate natural gas pipelines and gas gathering systems, provide various ancillary services, and offer variable and fixed price physical natural gas supplies to commercial and industrial customers and natural gas distributors. References to "we," "us," and "our" mean CenterPoint Energy Resources Corp. (CERC Corp., together with our subsidiaries, CERC). We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

Our reportable business segments are Natural Gas Distribution, Pipelines and Gathering and Other Operations.

CenterPoint Energy is a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (1935 Act). The 1935 Act and related rules and regulations impose a number of restrictions on the activities of CenterPoint Energy and those of its subsidiaries. The 1935 Act, among other things, limits the ability of CenterPoint Energy and its regulated subsidiaries to issue debt and equity securities without prior authorization, restricts the source of dividend payments to current and retained earnings without prior authorization, regulates sales and acquisitions of certain assets and businesses and governs affiliated service, sales and construction contracts.

Our principal executive offices are located at 1111 Louisiana, Houston, Texas 77002 (telephone number: 713-207-1111).

We make available free of charge on our parent company's Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the Securities and Exchange Commission (SEC). Our parent company's website address is www.centerpointenergy.com.

NATURAL GAS DISTRIBUTION

Local Distribution Companies

Our natural gas distribution business engages in intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas through three unincorporated divisions: Houston Gas, Minnesota Gas and Southern Gas Operations. In an effort to increase brand recognition, the naming conventions of our three unincorporated divisions were changed in 2004. CenterPoint Energy Arkla and the portion of CenterPoint Energy Entex (Entex) located outside of the metropolitan Houston area were renamed Southern Gas Operations. The metropolitan Houston portion of Entex was renamed Houston Gas, and CenterPoint Energy Minnegasco was renamed Minnesota Gas. These operations are regulated as natural gas utility operations in the jurisdictions served by these divisions.

Houston Gas provides natural gas distribution services to approximately 1,030,000 customers in over 100 communities in the Houston metropolitan area In 2004, approximately 99% of Houston Gas' total throughput was attributable to retail sales and approximately 1% was attributable to transportation services.

Minnesota Gas provides natural gas distribution services to approximately 750,000 customers in over 240 communities. The largest metropolitan area served by Minnesota Gas is Minneapolis. In 2004, approximately 91% of Minnesota Gas' total throughput was attributable to retail sales and approximately 9% was attributable to transportation services. Minnesota Gas also provides unregulated services consisting of heating, ventilating and air conditioning (HVAC) equipment and appliance repair, sales of HVAC, water heating and hearth equipment and home security monitoring.

Southern Gas Operations provides natural gas distribution services to approximately 1,260,000 customers in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. The largest metropolitan areas served by Southern Gas Operations are Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; Lawton, Oklahoma; and Laredo, Texas. In 2004, approximately 72% of Southern Gas Operations' total throughput was attributable to retail sales and approximately 28% was attributable to transportation services.

The demand for intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers is seasonal. In 2004, approximately 70% of the total throughput of our local distribution companies' business occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during those periods.

Supply and Transportation. In 2004, Houston Gas purchased virtually all of its natural gas supply pursuant to contracts, with remaining terms varying from a few months to two years. Houston Gas' major suppliers in 2004 included American Electric Power Company (50% of supply volumes) and Kinder Morgan Texas Pipeline (27%). Numerous other suppliers provided the remaining 23% of Houston Gas' natural gas supply requirements. Houston Gas transports its natural gas supplies through various interstate and intrastate pipelines under contracts with remaining terms varying from one to five years.

In 2004, Minnesota Gas purchased virtually all of its natural gas supply pursuant to contracts, with remaining terms varying from a few months to four years. Minnesota Gas' major suppliers in 2004 included BP Canada Energy Marketing (61% of supply volumes), Occidental Energy Marketing (6%), Tenaska Marketing Ventures (6%), Prairielands Energy Marketing (4%) and Oneok Energy Services Company (4%). Numerous other suppliers provided the remaining 19% of Minnesota Gas' natural gas supply requirements. Minnesota Gas transports its natural gas supplies through various interstate pipelines under contracts with remaining terms varying from one to eight years.

In 2004, Southern Gas Operations purchased virtually all of its natural gas supply pursuant to contracts, with remaining terms varying from a few months to five years. Southern Gas Operations' major suppliers in 2004 included BP Energy Company (23% of supply volumes), CenterPoint Energy Gas Services (CEGS), one of our subsidiaries, (18%), Entergy-Koch, LP (12%), Oneok Energy Marketing and Trading LLC (8%), American Electric Power Company (6%) and Conoco Phillips Company (5%). Numerous other suppliers provided the remaining 28% of Southern Gas Operations' natural gas supply requirements. Southern Gas Operations transports its natural gas supplies through various intrastate and interstate pipelines including CenterPoint Energy's pipeline subsidiary.

Generally, the regulations of the states in which our natural gas distribution business operates allow us to pass through changes in the costs of natural gas to our customers under purchased gas adjustment provisions in our tariffs.

Minnesota Gas and Southern Gas Operations use various leased or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. Minnesota Gas also supplements contracted supplies and storage from time to time with stored liquefied natural gas and propane-air plant production.

Minnesota Gas owns and operates an underground storage facility with a capacity of 7.0 billion cubic feet (Bcf). It has a working capacity of 2.1 Bcf available for use during a normal heating season and a maximum daily withdrawal rate of 50 million cubic feet (MMcf). It also owns nine propane-air plants with a total capacity of 204 MMcf per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf gas equivalent). Minnesota Gas owns liquefied natural gas plant facilities with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf gas equivalent) and a send-out capability of 72 MMcf per day.

On an ongoing basis, we enter into contracts to provide sufficient supplies and pipeline capacity to meet our customer requirements. However, it is possible for limited service disruptions of interruptible customers' load to occur from time to time due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time, or prices may increase rapidly in response to temporary supply constraints or other factors.

Non-Rate Regulated Gas Sales and Services

We offer variable and fixed priced physical natural gas supplies to commercial and industrial customers and natural gas distributors through a number of subsidiaries, primarily CEGS. In 2004, CEGS marketed approximately 579 Bcf (including 134 Bcf to affiliates) of natural gas, transportation and related energy services to more than 6,000 customers which varied in size from small commercial to large utility companies in the central regions of the United States. These customers are served from offices located in Illinois, Louisiana, Minnesota, Missouri, Texas and Wisconsin. The business has three operational functions: wholesale, retail and intrastate pipelines further described below.

Wholesale Operations. CEGS offers a portfolio of physical delivery services and financial products designed to meet wholesale customers' supply and price risk management needs.

Retail Operations. CEGS also offers a variety of natural gas management services to smaller commercial and industrial customers including load forecasting, supply acquisition, daily swing volume management, invoice consolidation, storage asset management, firm and interruptible transportation administration and forward price management. CEGS manages transportation contracts and energy supply for retail customers in ten states.

Intrastate Pipeline Operations. Another wholly owned subsidiary of ours owns and operates approximately 210 miles of intrastate pipeline in Louisiana and Texas. This subsidiary provides bundled and unbundled merchant and transportation services to shippers and end-users.

CEGS currently operates on over 30 pipelines throughout the central United States. CEGS maintains a portfolio of long-term natural gas supply contracts and firm transportation agreements to meet the natural gas requirements of its customers. CEGS aggregates supply from various producing regions and offer contracts to buy natural gas with terms ranging from one month to over five years. In addition, CEGS actively participates in the spot natural gas markets in an effort to balance daily and monthly purchases and sales obligations. Gas supply and transportation capabilities are leveraged through contracts for ancillary services including physical storage and other balancing arrangements.

As described above, CEGS offers its customers a variety of load following services. In providing these services, CEGS will use its customers' purchase commitments to forecast and arrange its own supply purchases and transportation services to serve customers' natural gas requirements. As a result of the variance between this forecast activity and the actual monthly activity, CEGS will either have too much supply or too little supply relative to its customers' purchase commitments. These supply imbalances arise each month as customers' natural gas requirements are scheduled and corresponding natural gas supplies are nominated by CEGS for delivery to these customers. CEGS' processes and risk control environment are designed to measure and value all supply imbalances on a real time basis to ensure that CEGS' exposure to commodity price and volume risk is kept to a minimum. The value assigned to these volumetric imbalances is calculated daily and is known as the aggregate Value at Risk (VaR). In 2004, CEGS' VaR averaged $0.2 million with a high of $1 million.

The CenterPoint Energy Risk Control policy, governed by the Risk Oversight Committee, defines authorized and prohibited trading instruments and volumetric trading limits. CEGS is a physical marketer of natural gas and uses a variety of tools, including pipeline and storage capacity, financial instruments and physical commodity purchase contracts to support its sales. The CEGS business optimizes its use of these various tools to minimize its supply costs and does not engage in proprietary or speculative commodity trading. The low VaR limits within which CEGS operates are consistent with its operational objective of matching its aggregate sales obligations (including the swing associated with load following services) with its supply portfolio in a manner that minimizes its total cost of supply.

Assets

As of December 31, 2004, we owned approximately 65,000 linear miles of gas distribution mains, varying in size from one-half inch to 24 inches in diameter. Generally, in each of the cities, towns and rural areas we serve, we own the underground gas mains and service lines, metering and regulating equipment located on customers' premises and the district regulating equipment necessary for pressure maintenance. With a few exceptions, the measuring stations at which we receive gas are owned, operated and maintained by others, and our distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on the land owned by suppliers.

Competition

We compete primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other gas distributors and marketers also compete directly for gas sales to end-users. In addition, as a result of federal regulatory changes affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass our facilities and market and sell and/or transport natural gas directly to commercial and industrial customers.

PIPELINES AND GATHERING

Our pipelines and gathering business operates two interstate natural gas pipelines, as well as gas gathering facilities and also provides operating and technical services and remote data monitoring and communication services. The rates charged by interstate pipelines for interstate transportation and storage services are regulated by the Federal Energy Regulatory Commission (FERC).

We own and operate gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. Our pipeline operations are primarily conducted by two wholly owned interstate pipeline subsidiaries which provide gas transportation and storage services primarily to industrial customers and local distribution companies:

- CenterPoint Energy Gas Transmission Company (CEGT) is an interstate pipeline that provides natural gas transportation, natural gas storage and pipeline services to customers principally in Arkansas, Louisiana, Oklahoma and Texas.

- CenterPoint Energy -- Mississippi River Transmission Corporation (MRT) is an interstate pipeline that provides natural gas transportation, natural gas storage and pipeline services to customers principally in Arkansas and Missouri.

Our gathering operations are conducted by a wholly owned gas gathering subsidiary, CenterPoint Energy Field Services, Inc. (CEFS). CEFS is a natural gas gathering and processing business serving natural gas fields in the Midcontinent basin of the United States that interconnect with CEGT's and MRT's pipelines, as well as other interstate and intrastate pipelines. CEFS operates gathering pipelines, which collect natural gas from approximately 200 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas. CEFS, through its Service Star operating division, provides remote data monitoring and communications services to affiliates and third parties. The Service Star operating division provides monitoring activities at over 6,000 locations across Alabama, Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, Texas and Wyoming.

Our pipeline project management and facility operation services are provided to affiliates and third parties through a wholly owned pipeline services subsidiary, CenterPoint Energy Pipeline Services, Inc.

In 2004, approximately 22% of our total operating revenue from pipelines and gathering was attributable to services provided to Southern Gas Operations and approximately 9% was attributable to services to Laclede Gas Company (Laclede), an unaffiliated distribution company that provides natural gas utility service to the greater St. Louis metropolitan area in Illinois and Missouri. Services to Southern Gas Operations and Laclede are provided under several long-term firm storage and transportation agreements. The agreement to provide services to Laclede expires in 2007. Agreements for firm transportation, no notice transportation service and storage service in Southern Gas Operations' major service areas (Arkansas, Louisiana and Oklahoma) have recently been entered into and expire in 2012. The Oklahoma agreements are subject to the approval of the Oklahoma Corporation Commission (OCC).

Our pipelines and gathering business operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Midcontinent and Gulf Coast natural gas supply regions and general economic conditions.

Assets

We own and operate approximately 8,200 miles of gas transmission lines primarily located in Missouri, Illinois, Arkansas, Louisiana, Oklahoma and Texas. We also own and operate six natural gas storage fields with a combined daily deliverability of approximately 1.2 Bcf per day and a combined working gas capacity of approximately 59.0 Bcf. We also own a 10% interest in Gulf South Pipeline Company, LP's Bistineau storage facility. This facility has a total working gas capacity of 73.8 Bcf and approximately 1.1 Bcf per day of deliverability. Our storage capacity in the Bistineau facility is 8 Bcf of working gas with 100 MMcf per day of deliverability. Most of our storage operations are in north Louisiana and Oklahoma. We also own and operate approximately 4,300 miles of gathering pipelines that collect, treat and process natural gas from approximately 200 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Competition

Our pipelines and gathering business competes with other interstate and intrastate pipelines and gathering companies in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service, and flexibility and reliability of service. Our pipelines and gathering business competes indirectly with other forms of energy available to our customers, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability of energy and pipeline capacity, the level of business activity, conservation and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas in areas we serve and the level of competition for transportation and storage services. In addition, competition for our gathering operations is impacted by commodity pricing levels because of their influence on the level of drilling activity. Both pipeline services and Service Star compete with other similar service companies based on market pricing. The principal elements of competition are rates, terms of service and reliability of services.

OTHER OPERATIONS

In 2004, Other Operations included unallocated corporate costs and inter-segment eliminations.

FINANCIAL INFORMATION ABOUT SEGMENTS

For financial information about our segments, see Note 12 to our consolidated financial statements, which note is incorporated herein by reference.

REGULATION

We are subject to regulation by various federal, state and local governmental agencies, including the regulations described below.

PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

As a subsidiary of a registered public utility holding company, we are subject to a comprehensive regulatory scheme imposed by the Securities and Exchange Commission (SEC) in order to protect customers, investors and the public interest. Although the SEC does not regulate rates and charges under the 1935 Act, it does regulate the structure, financing, lines of business and internal transactions of public utility holding companies and their system companies. In order to obtain financing, acquire additional public utility assets or stock, or engage in other significant transactions, we are generally required to obtain approval from the SEC under the 1935 Act.

CenterPoint Energy received an order from the SEC under the 1935 Act on June 30, 2003 and supplemental orders thereafter relating to its financing activities and those of its regulated subsidiaries, including us, as well as other matters. The orders are effective until June 30, 2005. As of December 31, 2004, the orders generally permitted CenterPoint Energy and its subsidiaries, including us, to issue securities to refinance indebtedness outstanding at June 30, 2003, and authorized CenterPoint Energy and its subsidiaries, including us, to issue certain incremental external debt securities and common and preferred stock through June 30, 2005 in specified amounts, without prior authorization from the SEC. The orders also contain certain requirements regarding ratings of CenterPoint Energy's securities, interest rates, maturities, issuance expenses and use of proceeds. The orders require that we maintain a ratio of common equity to total capitalization of at least 30%. We intend to file an application for approval of our post-June 30, 2005 financing activities.

The United States Congress from time to time considers legislation that would repeal the 1935 Act. We cannot predict at this time whether this legislation or any variation thereof will be adopted or, if adopted, the effect of any such law on our business.

FEDERAL ENERGY REGULATORY COMMISSION

The FERC has jurisdiction under the Natural Gas Act and the Natural Gas Policy Act of 1978, as amended, to regulate the transportation of natural gas in interstate commerce and natural gas sales for resale in intrastate commerce that are not first sales. The FERC regulates, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. The rates charged by interstate pipelines for interstate transportation and storage services are also regulated by the FERC.

Our natural gas pipeline subsidiaries may periodically file applications with the FERC for changes in their generally available maximum rates and charges designed to allow them to recover their costs of providing service to customers (to the extent allowed by prevailing market conditions), including a reasonable rate of return. These rates are normally allowed to become effective after a suspension period and, in some cases, are subject to refund under applicable law until such time as the FERC issues an order on the allowable level of rates.

On November 25, 2003, the FERC issued Order No. 2004, the final rule modifying the Standards of Conduct applicable to electric and natural gas transmission providers, governing the relationship between regulated transmission providers and certain of their affiliates. During 2004, the FERC Order was amended three times. The rule significantly changes and expands the regulatory burdens of the Standards of Conduct and applies essentially the same standards to jurisdictional electric transmission providers and natural gas pipelines. On February 9, 2004, our natural gas pipeline subsidiaries filed Implementation Plans required under the new rule. Those subsidiaries were further required to post their Implementation Procedures on their websites by September 22, 2004, and to be in compliance with the requirements of the new rule by that date.

STATE AND LOCAL REGULATION

In almost all communities in which we provide natural gas distribution services, we operate under franchises, certificates or licenses obtained from state and local authorities. The terms of the franchises, with various expiration dates, typically range from 10 to 30 years, though franchises in Arkansas are perpetual. None of our material franchises expire in the near term. We expect to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of our retail natural gas sales by our local distribution divisions are subject to traditional cost-of-service regulation at rates regulated by the relevant state public utility commissions and, in Texas, by the Railroad Commission of Texas (Railroad Commission) and municipalities we serve.

In 2004, the City of Houston, 28 other cities and the Railroad Commission approved a settlement that increased Houston Gas' base rate and service charge revenues by approximately $14 million annually.

In February 2004, the Louisiana Public Service Commission (LPSC) approved a settlement that increased Southern Gas Operations' base rate and service charge revenues in its South Louisiana Division by approximately $2 million annually.

In July 2004, Minnesota Gas filed an application for a general rate increase of $22 million with the Minnesota Public Utilities Commission (MPUC). Minnesota Gas and the Minnesota Department of Commerce have agreed to a settlement of all issues, including an annualized increase in the amount of $9 million, subject to approval by the MPUC. A final decision on this rate relief request is expected from the MPUC in the second quarter of 2005. Interim rates of $17 million on an annualized basis became effective on October 1, 2004, subject to refund.

In July 2004, the LPSC approved a settlement that increased Southern Gas Operations' base rate and service charge revenues in its North Louisiana Division by approximately $7 million annually.

In October 2004, Southern Gas Operations filed an application for a general rate increase of approximately $3 million with the Railroad Commission for rate relief in the unincorporated areas of its Beaumont, East Texas and South Texas Divisions. The Railroad Commission staff has begun its review of the request, and a decision is anticipated in April 2005.

In November 2004, Southern Gas Operations filed an application for a general rate increase of approximately $34 million with the Arkansas Public Service Commission (APSC). The APSC staff has begun its review of the request, and a decision is anticipated in the second half of 2005.

In December 2004, the OCC approved a settlement that increased Southern Gas Operations' base rate and service charge revenues in Oklahoma by approximately $3 million annually.

DEPARTMENT OF TRANSPORTATION

In December 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (the Act). This legislation applies to our interstate pipelines as well as our intrastate pipelines and local distribution companies. The legislation imposes several requirements related to ensuring pipeline safety and integrity. It requires pipeline and distribution companies to assess the integrity of their pipeline transmission facilities in areas of high population concentration or High Consequence Areas (HCA). The legislation further requires companies to perform remediation activities, in accordance with the requirements of the legislation, over a 10-year period.

In December 2003, the Department of Transportation Office of Pipeline Safety issued the final regulations to implement the Act. These regulations became effective on February 14, 2004 and provided guidance on, among other things, the areas that should be classified as HCA. Our interstate pipelines developed and implemented a written pipeline integrity management program in 2004, meeting the Department of Transportation Office of Pipeline Safety requirement of having the program in place by December 17, 2004.

Our interstate and intrastate pipelines and our natural gas distribution companies anticipate that compliance with the new regulations will require increases in both capital and operating cost. The level of expenditures required to comply with these regulations will be dependent on several factors, including the age of the facility, the pressures at which the facility operates and the number of facilities deemed to be located in areas designated as HCA. Based on our interpretation of the rules and preliminary technical reviews, we anticipate compliance will require average annual expenditures of approximately $15 to $20 million during the initial 10-year period.

ENVIRONMENTAL MATTERS

Our operations are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of natural gas pipelines and gas gathering and processing systems, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of our wastes;

- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;

- requiring remedial action to mitigate pollution conditions caused by our operations, or attributable to former operations; and

- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

In order to comply with these requirements, we may need to spend substantial amounts and devote other resources from time to time to:

- construct or acquire new equipment;

- acquire permits for facility operations;

- modify or replace existing and proposed equipment; and

- clean up or decommission waste disposal areas, fuel storage and management facilities and other locations and facilities.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. In addition, we believe that the various environmental remediation activities in which we are presently engaged will not materially interrupt or diminish our operational ability. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs. The following is a discussion of all material environmental and safety laws and regulations that relate to our operations. We believe that we are in substantial compliance with all of these environmental laws and regulations.

AIR EMISSIONS

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

WATER DISCHARGES

Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into waters of the United States. The unpermitted discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

HAZARDOUS WASTE

Our operations generate wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act (RCRA), and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes are still regulated under state law and the less stringent non-hazardous waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

LIABILITY FOR REMEDIATION

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum as well as natural gas is excluded from CERCLA's definition of "hazardous substance," in the course of our ordinary operations we generate wastes that may fall within the definition of a "hazardous substance." CERCLA authorizes the United States Environmental Protection Agency (EPA) and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

LIABILITY FOR PREEXISTING CONDITIONS

Hydrocarbon Contamination. We and certain of our subsidiaries are among the defendants in lawsuits filed beginning in August 2001 in Caddo Parish and Bossier Parish, Louisiana. The suits allege that, at some unspecified date prior to 1985, the defendants allowed or caused hydrocarbon or chemical contamination of the Wilcox Aquifer, which lies beneath property owned or leased by certain of the defendants and which is the sole or primary drinking water aquifer in the area. The primary source of the contamination is alleged by the plaintiffs to be a gas processing facility in Haughton, Bossier Parish, Louisiana known as the "Sligo Facility," which was formerly operated by a predecessor in interest of CERC Corp. This facility was purportedly used for gathering natural gas from surrounding wells, separating gasoline and hydrocarbons from the natural gas for marketing, and transmission of natural gas for distribution. Beginning about 1985, the predecessors of certain CERC Corp. defendants engaged in a voluntary remediation of any subsurface contamination of the groundwater below the property they owned or leased. This work has been done in conjunction with and under the direction of the Louisiana Department of Environmental

Quality. The plaintiffs seek monetary damages for alleged damage to the aquifer underlying their property, unspecified alleged personal injuries, alleged fear of cancer, alleged property damage or diminution of value of their property, and, in addition, seek damages for trespass, punitive, and exemplary damages. We believe the ultimate cost associated with resolving this matter will not have a material impact on our financial condition or results of operations.

Manufactured Gas Plant Sites. We and our predecessors operated manufactured gas plants (MGP) in the past. In Minnesota, we have completed remediation on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in our Minnesota service territory. We believe that we have no liability with respect to two of these sites.

At December 31, 2004, we had accrued $18 million for remediation of certain Minnesota sites. At December 31, 2004, the estimated range of possible remediation costs for these sites was $7 million to $42 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. We have utilized an environmental expense tracker mechanism in our rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2004, we have collected or accrued $13 million from insurance companies and ratepayers to be used for future environmental remediation.

In addition to the Minnesota sites, the EPA and other regulators have investigated MGP sites that we owned or operated or may have been owned or operated by one of our former affiliates. We have been named as a defendant in lawsuits under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by our former affiliates or divisions. We have also been identified as a PRP by the State of Maine for a site that is the subject of one of the lawsuits. We are investigating details regarding these sites and the range of environmental expenditures for potential remediation. However, we believe we are not liable as a former owner or operator of those sites under CERCLA and applicable state statutes, and are vigorously contesting those suits and our designation as a PRP.

Mercury Contamination. Our pipeline and distribution operations have in the past employed elemental mercury in measuring and regulating equipment. It is possible that small amounts of mercury may have been spilled in the course of normal maintenance and replacement operations and that these spills may have contaminated the immediate area with elemental mercury. We have found this type of contamination at some sites in the past, and we have conducted remediation at these sites. It is possible that other contaminated sites may exist and that remediation costs may be incurred for these sites. Although the total amount of these costs cannot be known at this time, based on our experience and that of others in the natural gas industry to date and on the current regulations regarding remediation of these sites, we believe that the costs of any remediation of these sites will not be material to our financial condition, results of operations or cash flows.

Other Environmental. From time to time, we have received notices from regulatory authorities or others regarding our status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. Although their ultimate outcome cannot be predicted at this time, we do not believe, based on our experience to date, that these matters, either individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

EMPLOYEES

As of December 31, 2004, we had 5,194 full-time employees. The following table sets forth the number of our employees by business segment as of December 31, 2004:

BUSINESS SEGMENT	NUMBER	NUMBER REPRESENTED BY UNIONS OR OTHER COLLECTIVE BARGAINING GROUPS
Natural Gas Distribution	4,517	1,538
Pipelines and Gathering	677	--
Total	5,194	1,538

As of December 31, 2004, approximately 30% of our employees are subject to collective bargaining agreements. Four of these agreements, covering approximately 15% of our employees, have expired or will expire in 2005.

RISK FACTORS

PRINCIPAL RISK FACTORS ASSOCIATED WITH OUR BUSINESSES

RATE REGULATION OF OUR BUSINESS MAY DELAY OR DENY OUR ABILITY TO EARN A REASONABLE RETURN AND FULLY RECOVER OUR COSTS.

Our rates for our local distribution companies are regulated by certain municipalities and state commissions based on an analysis of our invested capital and our expenses incurred in a test year. Thus, the rates that we are allowed to charge may not match our expenses at any given time. While rate regulation in the applicable jurisdictions is, generally, premised on providing an opportunity to recover reasonable and necessary operating expenses and to earn a reasonable return on invested capital, there can be no assurance that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs and enable us to earn a reasonable return on our invested capital.

OUR BUSINESSES MUST COMPETE WITH ALTERNATIVE ENERGY SOURCES, AND OUR PIPELINES AND GATHERING BUSINESSES MUST COMPETE DIRECTLY WITH OTHERS IN THE TRANSPORTATION, STORAGE, GATHERING, TREATING AND PROCESSING OF NATURAL GAS.

We compete primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other natural gas distributors and marketers also compete directly with us for natural gas sales to end-users. In addition, as a result of federal regulatory changes affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass our facilities and market, sell and/or transport natural gas directly to commercial and industrial customers. Any reduction in the amount of natural gas we market, sell or transport as a result of competition may have an adverse impact on our results of operations, financial condition and cash flows.

Our two interstate pipelines and our gathering systems compete with other interstate and intrastate pipelines and gathering systems in the transportation and storage of natural gas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service. They also compete indirectly with other forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price. The actions of our competitors could lead to lower prices, which may have an adverse impact on our results of operations, financial condition and cash flows.

OUR NATURAL GAS DISTRIBUTION BUSINESS IS SUBJECT TO FLUCTUATIONS IN NATURAL GAS PRICING LEVELS.

We are subject to risk associated with price movements of natural gas. Movements in natural gas prices might affect our ability to collect balances due from our customers and, on the regulated side, could create the potential for uncollectible accounts expense to exceed the recoverable levels built into our tariff rates. In addition, a sustained period of high natural gas prices could apply downward demand pressure on natural gas consumption in the areas in which we operate and increase the risk that our suppliers or customers fail or are unable to meet their obligations. Additionally, increasing gas prices could create the need for us to provide collateral in order to purchase gas.

IF WE WERE TO FAIL TO EXTEND A CONTRACT WITH ONE OF OUR SIGNIFICANT PIPELINE CUSTOMERS, THERE COULD BE AN ADVERSE IMPACT ON OUR OPERATIONS.

Our contract with Laclede Gas Company, one of our pipeline customers, is currently scheduled to expire in 2007. To the extent the pipeline is unable to extend this contract or the contract is renegotiated at rates substantially less than the rates provided in the current contract, there could be an adverse effect on our results of operations, financial condition and cash flows.

A DECLINE IN OUR CREDIT RATING COULD RESULT IN US HAVING TO PROVIDE COLLATERAL IN ORDER TO PURCHASE GAS.

If our credit rating were to decline, we might be required to post cash collateral in order to purchase natural gas. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, we might be unable to obtain the necessary natural gas to meet our contractual distribution obligations, and our results of operations, financial condition and cash flows would be adversely affected.

OUR INTERSTATE PIPELINES' AND NATURAL GAS GATHERING AND PROCESSING BUSINESS' REVENUES AND RESULTS OF OPERATIONS ARE SUBJECT TO FLUCTUATIONS IN THE SUPPLY OF GAS.

Our interstate pipelines and natural gas gathering and processing businesses largely rely on gas sourced in the various supply basins located in the Midcontinent region of the United States. To the extent the availability of this supply is substantially reduced, it could have an adverse effect on our results of operations, financial condition and cash flows.

OUR REVENUES AND RESULTS OF OPERATIONS ARE SEASONAL.

A substantial portion of our revenues are derived from natural gas sales and transportation. Thus, our revenues and results of operations are subject to seasonality, weather conditions and other changes in natural gas usage, with revenues being higher during the winter months.

RISK FACTORS ASSOCIATED WITH OUR CONSOLIDATED FINANCIAL CONDITION

IF WE ARE UNABLE TO ARRANGE FUTURE FINANCINGS ON ACCEPTABLE TERMS, OUR ABILITY TO REFINANCE EXISTING INDEBTEDNESS COULD BE LIMITED.

As of December 31, 2004, we had $2.4 billion of outstanding indebtedness. As of March 11, 2005, approximately $518 million principal amount of this debt must be paid through 2006. The success of our future financing efforts may depend, at least in part, on:

- general economic and capital market conditions;

- credit availability from financial institutions and other lenders;

- investor confidence in us and the markets in which we operate;

- maintenance of acceptable credit ratings by us and by CenterPoint Energy;

- market expectations regarding our future earnings and probable cash flows;

- market perceptions of our ability to access capital markets on reasonable terms;

- provisions of relevant tax and securities laws; and

- our ability to obtain approval of specific financing transactions under the 1935 Act.

Our current credit ratings are discussed in "Management's Narrative Analysis of the Results of Operations -- Liquidity -- Impact on Liquidity of a Downgrade in Credit Ratings" in Item 7 of Part II of this report. We cannot assure you that these credit ratings will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to access capital on acceptable terms.

THE FINANCIAL CONDITION AND LIQUIDITY OF OUR PARENT COMPANY COULD AFFECT OUR ACCESS TO CAPITAL, OUR CREDIT STANDING AND OUR FINANCIAL CONDITION.

Our ratings and credit may be impacted by CenterPoint Energy's credit standing. As of March 11, 2005, CenterPoint Energy and its other subsidiaries have approximately $1.3 billion principal amount of debt required to be paid through 2006. This amount excludes amounts related to capital leases, securitization debt and indexed debt securities obligations. We cannot assure you that CenterPoint Energy and its other subsidiaries will be able to pay or refinance these amounts. If CenterPoint Energy were to experience a deterioration in its credit standing or liquidity difficulties, our access to credit and our credit ratings could be adversely affected.

WE ARE AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY. CENTERPOINT ENERGY CAN EXERCISE SUBSTANTIAL CONTROL OVER OUR DIVIDEND POLICY AND BUSINESS AND OPERATIONS AND COULD DO SO IN A MANNER THAT IS ADVERSE TO OUR INTERESTS.

We are managed by officers and employees of CenterPoint Energy. Our management will make determinations with respect to the following:

- our payment of dividends;
- decisions on our financings and our capital raising activities;
- mergers or other business combinations; and
- our acquisition or disposition of assets.

There are no contractual restrictions on our ability to pay dividends to CenterPoint Energy. Our management could decide to increase our dividends to CenterPoint Energy to support its cash needs. This could adversely affect our liquidity. Under the 1935 Act, our ability to pay dividends is restricted by the SEC's requirement that common equity as a percentage of total capitalization must be at least 30% after the payment of any dividend. Under our credit facility and our receivables facility, our ability to pay dividends is restricted by a covenant that debt as a percentage of total capitalization may not exceed 60%.

THE USE OF DERIVATIVE CONTRACTS BY US AND OUR SUBSIDIARIES IN THE NORMAL COURSE OF BUSINESS COULD RESULT IN FINANCIAL LOSSES THAT NEGATIVELY IMPACT OUR RESULTS OF OPERATIONS AND THOSE OF OUR SUBSIDIARIES.

We use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. We could recognize financial losses as a result of volatility in the market values of these contracts, or if a counterparty fails to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

OTHER RISKS

WE, AS A SUBSIDIARY OF CENTERPOINT ENERGY, A HOLDING COMPANY, ARE SUBJECT TO REGULATION UNDER THE 1935 ACT. THE 1935 ACT AND RELATED RULES AND REGULATIONS IMPOSE A NUMBER OF RESTRICTIONS ON OUR ACTIVITIES.

CenterPoint Energy and its subsidiaries, including us, are subject to regulation by the SEC under the 1935 Act. The 1935 Act, among other things, limits the ability of a holding company and its regulated subsidiaries to issue debt and equity securities without prior authorization, restricts the source of dividend payments to current and retained earnings without prior authorization, regulates sales and acquisitions of certain assets and businesses and governs affiliated service, sales and construction contracts.

CenterPoint Energy received an order from the SEC under the 1935 Act on June 30, 2003 relating to its financing activities, which is effective until June 30, 2005. Although authorized levels of financing, together with current levels of liquidity, are believed to be adequate during the period the order is effective, unforeseen events could result in capital needs in excess of authorized amounts, necessitating further authorization from the SEC. Approval of filings under the 1935 Act can take extended periods.

We must seek a new financing order under the 1935 Act for approval of our post-June 30, 2005 financing activities before the current financing order expires on June 30, 2005. If we are unable to obtain a new financing order, we would generally be unable to engage in any financing transactions, including the refinancing of existing obligations after June 30, 2005.

The United States Congress from time to time considers legislation that would repeal the 1935 Act. We cannot predict at this time whether this legislation or any variation thereof will be adopted or, if adopted, the effect of any such law on our business.

OUR INSURANCE COVERAGE MAY NOT BE SUFFICIENT. INSUFFICIENT INSURANCE COVERAGE AND INCREASED INSURANCE COSTS COULD ADVERSELY IMPACT OUR RESULTS OF OPERATIONS, FINANCIAL CONDITION AND CASH FLOWS.

We currently have general liability and property insurance in place to cover certain of our facilities in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles and do not include business interruption coverage. We cannot assure you that insurance coverage will be available in the future at current costs or on commercially reasonable terms or that the insurance proceeds received for any loss of or any damage to any of our facilities will be sufficient to restore the loss or damage without negative impact on our results of operations, financial condition and cash flows.

ITEM 2. PROPERTIES

CHARACTER OF OWNERSHIP

We own our principal properties in fee. Most of our gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

NATURAL GAS DISTRIBUTION

For information regarding the properties of our Natural Gas Distribution business segment, please read "Our Business -- Natural Gas Distribution" in Item 1 of this report, which information is incorporated herein by reference.

PIPELINES AND GATHERING

For information regarding the properties of our Pipelines and Gathering business segment, please read "Our Business -- Pipelines and Gathering" in Item 1 of this report, which information is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS

For a brief description of certain legal and regulatory proceedings affecting us, please read "Regulation" and "Environmental Matters" in Item 1 of this report and Notes 3, 9(c) and 9(d) to our consolidated financial statements, which information is incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The information called for by Item 4 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

All of the 1,000 outstanding shares of CERC Corp.'s common stock are held by Utility Holding, LLC, a wholly owned subsidiary of CenterPoint Energy.

Our ability to pay dividends is restricted by the SEC's requirement that common equity as a percentage of total capitalization must be at least 30% after the payment of any dividend. In addition, the SEC restricts our ability to pay dividends out of capital accounts to the extent current or retained earnings are insufficient for those dividends.

In 2003, we paid no dividends on our common stock. In 2004, we paid dividends on our common stock of $12.5 million to Utility Holding, LLC.

ITEM 6. SELECTED FINANCIAL DATA

The information called for by Item 6 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 7. MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The following narrative analysis should be read in combination with our consolidated financial statements and notes contained in Item 8 of this report.

BACKGROUND

We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company created on August 31, 2002, as part of a corporate restructuring of Reliant Energy, Incorporated (Reliant Energy). Our operating subsidiaries own and operate natural gas distribution facilities, interstate pipelines and natural gas gathering, processing and treating facilities.

CenterPoint Energy is a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (1935 Act). For information about the 1935 Act, please read " -- Liquidity -- Certain Contractual and Regulatory Limits on Ability to Issue Securities and Pay Dividends."

BUSINESS SEGMENTS

Because we are an indirect wholly owned subsidiary of CenterPoint Energy, our determination of reportable segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. We have identified the following reportable business segments: Natural Gas Distribution, Pipelines and Gathering and Other Operations.

NATURAL GAS DISTRIBUTION

Our natural gas distribution business engages in intrastate natural gas sales to, and natural gas transportation for, approximately 3 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. These operations are regulated as natural gas utility operations. Our operations also include non-rate regulated retail and wholesale gas sales to, and transportation services for, commercial and industrial customers in the six states listed above as well as several other Midwestern states.

PIPELINES AND GATHERING

Our pipelines and gathering business operates two interstate natural gas pipelines as well as gas gathering facilities and also provides pipeline services. Our gathering operations are conducted by a wholly owned gas gathering subsidiary, CenterPoint Energy Field Services, Inc. (CEFS). CEFS is a natural gas gathering and processing business serving natural gas fields in the Midcontinent basin of the United States that interconnect with our pipelines, as well as other interstate and intrastate pipelines. CEFS operates gathering pipelines, which collect natural gas from approximately 200 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas. CEFS, through its Service Star operating division, provides remote data monitoring and communications services to affiliates and third parties. The Service Star operating division provides monitoring activities at over 6,000 locations across Alabama, Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, Texas and Wyoming.

OTHER OPERATIONS

Our Other Operations business segment includes unallocated corporate costs and inter-segment eliminations.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

Our past earnings and results of operations are not necessarily indicative of our future earnings and results of operations. The magnitude of our future earnings and results of our operations will depend on or be affected by numerous factors including:

- state and federal legislative and regulatory actions or developments, constraints placed on our activities or business by the 1935 Act, changes in or application of laws or regulations applicable to other aspects of our business;

- timely rate increases, including recovery of costs;

- industrial, commercial and residential growth in our service territory and changes in market demand and demographic patterns;

- the timing and extent of changes in commodity prices, particularly natural gas;

- changes in interest rates or rates of inflation;

- weather variations and other natural phenomena;

- the timing and extent of changes in the supply of natural gas;

- commercial bank and financial market conditions, our access to capital, the costs of such capital, receipt of certain financing approvals under the 1935 Act, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;

- actions by rating agencies;

- inability of various counterparties to meet their obligations to us;

- non-payment of our services due to financial distress of our customers;

- our ability to control costs;

- the investment performance of CenterPoint Energy's employee benefit plans;

- our internal restructuring or other restructuring options that may be pursued;

- our potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to us; and

- other factors discussed in Item 1 of this report under "Risk Factors."

CONSOLIDATED RESULTS OF OPERATIONS

Our results of operations are affected by seasonal fluctuations in the demand for natural gas and price movements of energy commodities. Our results of operations are also affected by, among other things, the actions of various federal and state governmental authorities having jurisdiction over rates we charge, competition in our various business operations, debt service costs and income tax expense.

The following table sets forth selected financial data for the years ended December 31, 2002, 2003 and 2004, followed by a discussion of our consolidated results of operations based on operating income. We have provided a reconciliation of consolidated operating income to net income below.

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
	(IN MILLIONS)		
Revenues	$ 4,208	$ 5,650	$ 6,983
Expenses:			
Natural gas	2,901	4,297	5,524
Operation and maintenance	667	688	732
Depreciation and amortization	167	176	187
Taxes other than income taxes	120	130	147
Total	3,855	5,291	6,590
Operating Income	353	359	393
Interest and other finance charges	(153)	(179)	(178)
Other income, net	8	8	16
Income Before Income Taxes	208	188	231
Income Tax Expense	(88)	(59)	(87)
Net Income	$ 120	$ 129	$ 144

2004 Compared to 2003. We reported net income of $144 million for 2004 as compared to $129 million for 2003. The increase in net income of $15 million was primarily due to increased operating income of $20 million in our Natural Gas Distribution business segment, primarily due to rate increases, and increased operating income of $22 million in our Pipelines and Gathering business segment, primarily from increased throughput, favorable commodity prices and increased ancillary services.

Our effective tax rate for 2004 and 2003 was 37.5% and 31.3%, respectively. The increase in the effective rate for 2004 compared to 2003 was primarily the result of a non-recurring decreased tax expense in 2003 relating to our Minnesota operations.

2003 Compared to 2002. We reported net income of $129 million for 2003 as compared to $120 million for 2002. The increase in net income of $9 million was primarily due to increased operating income of $4 million in our Natural Gas Distribution business segment, primarily due to rate increases, and increased operating income of $5 million in our Pipelines and Gathering business segment, primarily from favorable commodity prices and increased ancillary services.

Our effective tax rate for 2003 and 2002 was 31.3% and 42.2%, respectively. The decrease in the effective rate for 2003 compared to 2002 was primarily the result of a non-recurring decreased tax expense in 2003 relating to our Minnesota operations.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following tables present operating income for our Natural Gas Distribution and Pipelines and Gathering business segments for 2002, 2003 and 2004. Some amounts from the previous years have been reclassified to conform to the 2004 presentation of the financial statements. These reclassifications do not affect consolidated net income.

NATURAL GAS DISTRIBUTION

The following table provides summary data of our Natural Gas Distribution business segment for 2002, 2003 and 2004 (in millions):

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
Operating Revenues	$ 3,960	$ 5,435	$ 6,684
Operating Expenses:			
Natural gas	2,995	4,428	5,631
Operation and maintenance	539	560	566
Depreciation and amortization	126	136	143
Taxes other than income taxes	102	109	122
Total operating expenses	3,762	5,233	6,462
Operating Income	$ 198	$ 202	$ 222

2004 Compared to 2003. Our Natural Gas Distribution business segment reported operating income of $222 million for 2004 as compared to $202 million for 2003. Increases in operating income of $4 million from continued customer growth with the addition of 45,000 customers since December 31, 2003, $15 million from rate increases, $11 million from the impact of the 2003 change in estimate of margins earned on unbilled revenues implemented in 2003 and $9 million related to certain regulatory adjustments made to the amount of recoverable gas costs in 2003 were partially offset by the $8 million impact of milder weather. Operations and maintenance expense increased $6 million for 2004 as compared to 2003. Excluding an $8 million charge recorded in the first quarter of 2004 for severance costs associated with staff reductions, which has reduced costs in later periods, operation and maintenance expenses decreased by $2 million.

2003 Compared to 2002. Our Natural Gas Distribution business segment's operating income increased $4 million in 2003 compared to 2002 primarily due to higher revenues from rate increases implemented late in 2002 ($33 million), improved margins from our unregulated commercial and industrial sales ($6 million) and continued customer growth with the addition of over 38,000 customers since December 2002 ($6 million). These increases were partially offset by decreased revenues as a result of a decrease in the estimate of margins earned on unbilled revenues ($11 million). Additionally, operating income was negatively impacted by higher employee benefit expenses primarily due to increased pension costs ($13 million), certain costs being included in operating expense subsequent to the amendment of a receivables facility in November 2002 as compared to being included in interest expense in the prior year ($7 million) and increased bad debt expense primarily due to higher gas prices ($9 million).

PIPELINES AND GATHERING

The following table provides summary data of our Pipelines and Gathering business segment for 2002, 2003 and 2004 (in millions):

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
Operating Revenues	$ 374	$ 407	$ 451
Operating Expenses:			
Natural gas	32	61	46
Operation and maintenance	130	129	164
Depreciation and amortization	41	40	44
Taxes other than income taxes	18	19	17
Total operating expenses	221	249	271
Operating Income	$ 153	$ 158	$ 180

2004 Compared to 2003. Our Pipelines and Gathering business segment's operating income increased by $22 million in 2004 compared to 2003. Operating margins (revenues less fuel costs) increased by $59 million primarily due to favorable commodity pricing ($3 million), increased demand for certain transportation services driven by commodity price volatility ($36 million) and increased throughput and enhanced services related to our core gas gathering operations ($11 million). The increase in operating margin was partially offset by higher operation and maintenance expenses of $35 million primarily due to compliance with pipeline integrity regulations ($4 million) and costs relating to environmental matters ($9 million). Project work expenses included in operation and maintenance expense increased ($11 million) resulting in a corresponding increase in revenues billed for these services ($15 million).

2003 Compared to 2002. Our Pipelines and Gathering business segment's operating income increased $5 million in 2003 compared to 2002. The increase was primarily a result of increased margins (revenues less fuel costs) due to higher commodity prices ($8 million), improved margins from new transportation contracts to power plants ($7 million) and improved margins from enhanced services in our gas gathering operations ($4 million), partially offset by higher pension, employee benefit and other miscellaneous expenses ($14 million). Project work expenses included in operation and maintenance expense decreased ($15 million) resulting in a corresponding decrease in revenues billed for these services ($14 million).

FLUCTUATIONS IN COMMODITY PRICES AND DERIVATIVE INSTRUMENTS

For information regarding our exposure to risk as a result of fluctuations in commodity prices and derivative instruments, please read "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this report.

LIQUIDITY

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, and working capital needs. Our principal cash requirements during 2005 are approximately $357 million of capital expenditures and $361 million principal amount of maturing debt. We expect that borrowings under our credit facility, anticipated cash flows from operations and borrowings from affiliates will be sufficient to meet our cash needs for 2005.

The 1935 Act regulates our financing ability, as more fully described in "--Certain Contractual and Regulatory Limits on Ability to Issue Securities and Pay Dividends" below.

Capital Requirements. We anticipate investing up to an aggregate $1.6 billion in capital expenditures in the years 2005 through 2009. The following table sets forth our capital expenditures for 2004 and estimates of our capital requirements for 2005 through 2009 (in millions):

2004.............................	$ 269
2005.............................	357
2006.............................	343
2007.............................	281
2008.............................	260
2009.............................	312

The following table sets forth estimates of our contractual obligations to make future payments for 2005 through 2009 and thereafter (in millions):

CONTRACTUAL OBLIGATIONS(1)	TOTAL	2005	2006	2007	2008	2009	2010 AND THEREAFTER
Long-term debt, including current portion(2)......	$ 2,368	$ 367	$ 158	$ 7	$ 307	$ 7	$ 1,522
Operating leases(3)..............................	91	20	16	12	11	6	26
Non-trading derivative liabilities................	33	26	--	4	2	1	--
Other commodity commitments(4)....................	1,432	807	401	193	29	1	1
Total contractual cash obligations..............	$ 3,924	$ 1,220	$ 575	$ 216	$ 349	$ 15	$ 1,549

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(1) We expect to contribute approximately $16 million to our postretirement benefits plan in 2005 to fund a portion of our obligations in accordance with rate orders or to fund pay-as-you-go costs associated with the plan.

(2) The amounts reflected for long-term debt obligations in the table above do not include interest.

(3) For a discussion of operating leases, please read Note 9(b) to our consolidated financial statements.

(4) For a discussion of other commodity commitments, please read Note 9(a) to our consolidated financial statements.

Off-Balance Sheet Arrangements. Other than operating leases, we have no off-balance sheet arrangements. However, we do participate in a receivables factoring arrangement. We formed a bankruptcy remote subsidiary, which we consolidate, for the sole purpose of buying receivables created by us and selling those receivables to an unrelated third party. This transaction is accounted for as a sale of receivables under the provisions of SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and, as a result, the related receivables are excluded from the Consolidated Balance Sheets. In January 2004, the $100 million receivables facility was replaced with a $250 million receivables facility terminating in January 2005. In January 2005, the facility was extended to January 2006 and temporarily increased, for the period from January 2005 to June 2005, to $375 million. For additional information regarding this transaction please read Note 2(i) to our consolidated financial statements.

Credit Facilities. As of March 11, 2005, we had a $250 million credit facility under which no borrowings had been made. The credit facility terminates on March 23, 2007.

Securities Registered with the SEC. At December 31, 2004, we had a shelf registration statement covering $50 million of debt securities.

Money Pool. We participate in a "money pool" through which we and certain of our affiliates can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The money pool's net funding requirements are generally met by borrowings of CenterPoint Energy. The terms of the money pool are in accordance with requirements applicable to registered public utility holding companies under the 1935 Act and under an order from the SEC dated June 30, 2003 (June 2003 Financing Order) relating to our financing activities. The order expires in June 2005; however, we will seek approval for subsequent participation in the money pool prior to that date. Our money pool borrowing limit under such financing orders is $600 million. At December 31, 2004, we had $42 million invested in the money pool. The money pool may not provide sufficient funds to meet our cash needs.

Impact on Liquidity of a Downgrade in Credit Ratings. As of March 24, 2005, Moody's Investors Service, Inc. (Moody's), Standard & Poor's Ratings Services, a division of The McGraw Hill Companies (S&P) and Fitch, Inc. (Fitch) had assigned the following credit ratings to our senior unsecured debt:

MOODY'S		S&P		FITCH	
RATING	REVIEW(1)	RATING	OUTLOOK(2)	RATING	OUTLOOK(3)
Ba1	Possible Upgrade	BBB	Negative	BBB	Stable

- ------------------------

(1) A "review for possible upgrade" from Moody's indicates that a rating is under review for possible change in the short-term, usually within 90 days.

(2) An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate to longer term.

(3) A "stable" outlook from Fitch encompasses a one-to-two year horizon as to the likely ratings direction.

We cannot assure you that these ratings will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing, the cost of such financings, the willingness of suppliers to extend credit lines to us on an unsecured basis and the execution of our commercial strategies.

A decline in credit ratings would increase borrowing costs under our $250 million revolving credit facility. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and would negatively impact our ability to complete capital market transactions as more fully described in " --

Certain Contractual and Regulatory Limits on Ability to Issue Securities and Pay Dividends" below. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce margins of our Natural Gas Distribution business segment.

Our credit facility contains a "material adverse change" clause which relates to our ability to perform our obligations under the credit agreement.

CenterPoint Energy Gas Services, Inc. (CEGS), one of our wholly owned subsidiaries, provides comprehensive natural gas sales and services to industrial and commercial customers that are primarily located within or near the territories served by our pipelines and natural gas distribution subsidiaries. In order to hedge its exposure to natural gas prices, CEGS has agreements with provisions standard for the industry that establish credit thresholds and require a party to provide additional collateral on two business days' notice when that party's rating or the rating of a credit support provider for that party (CERC Corp. in this case) falls below those levels. As of December 31, 2004, our senior unsecured debt was rated BBB by S&P and Ba1 by Moody's. We estimate that as of December 31, 2004, unsecured credit limits extended to CEGS by counterparties could aggregate $100 million; however, utilized credit capacity is significantly lower.

Cross Defaults. Under CenterPoint Energy's revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $50 million by us will cause a default. Pursuant to the indenture governing CenterPoint Energy's senior notes, a payment default by us, in respect of, or an acceleration of, borrowed money and certain other specified types of obligations, in the aggregate principal amount of $50 million will cause a default. As of February 28, 2005, CenterPoint Energy had issued five series of senior notes aggregating $1.4 billion in principal amount under this indenture. A default by CenterPoint Energy would not trigger a default under our debt instruments or bank credit facilities.

Other Factors that Could Affect Cash Requirements. In addition to the above factors, our liquidity and capital resources could be affected by:

- cash collateral requirements that could exist in connection with certain contracts, including gas purchases, gas price hedging and gas storage activities of our Natural Gas Distribution business segment, particularly given gas price levels and volatility;

- acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of suppliers;

- increased costs related to the acquisition of gas for storage;

- increases in interest expense in connection with debt refinancings;

- various regulatory actions; and

- various of the risks identified in "Risk Factors."

Certain Contractual and Regulatory Limits on Ability to Issue Securities and Pay Dividends. Limitations imposed on us under the 1935 Act affect our ability to issue securities, pay dividends on our common stock or take other actions to adjust our capitalization.

Our bank facility and our receivables facility limit our debt as a percentage of our total capitalization to 60% and contain an earnings before interest, taxes, depreciation and amortization (EBITDA) to interest covenant.

Our parent, CenterPoint Energy, is a registered public utility holding company under the 1935 Act. The 1935 Act and related rules and regulations impose a number of restrictions on our parent's activities and those of its subsidiaries, including us. The 1935 Act, among other things, limits our parent's ability and the ability of its regulated subsidiaries, including us, to issue debt and equity securities without prior authorization, restricts the source of dividend payments to current and retained earnings without prior authorization, regulates sales and acquisitions of certain assets and businesses and governs affiliated service, sales and construction contracts.

The June 2003 Financing Order is effective until June 30, 2005. Additionally, CenterPoint Energy has received several subsequent orders which provide additional financing authority. These orders establish limits on the amount of external debt and equity securities that can be issued by CenterPoint Energy and its regulated subsidiaries, including us, without additional authorization but generally permit CenterPoint Energy and its regulated subsidiaries, including us, to refinance our existing obligations. We are in compliance with the authorized limits. The orders also permit our utilization of undrawn credit facilities. As of February 28, 2005, we are authorized to issue an additional $2 million of debt and an additional aggregate $250 million of preferred stock and preferred securities. The SEC has reserved jurisdiction over, and must take further action to permit, the issuance of $430 million of additional debt by us.

The orders require that if CenterPoint Energy or any of its regulated subsidiaries, including us, issue any securities that are rated by a nationally recognized statistical rating organization (NRSRO), the security to be issued must obtain an investment grade rating from at least one NRSRO and, as a condition to such issuance, all outstanding rated securities of the issuer and of CenterPoint Energy must be rated investment grade by at least one NRSRO. The orders also contain certain requirements for interest rates, maturities, issuance expenses and use of proceeds.

The 1935 Act limits the payment of dividends to payment from current and retained earnings unless specific authorization is obtained to pay dividends from other sources. The June 2003 Financing Order requires us to maintain a ratio of common equity to total capitalization of 30%.

Relationship with CenterPoint Energy. We are an indirect wholly owned subsidiary of CenterPoint Energy. As a result of this relationship, the financial condition and liquidity of our parent company could affect our access to capital, our credit standing and our financial condition.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the presentation of our financial condition and results of operations and requires management to make difficult, subjective or complex accounting estimates. An accounting estimate is an approximation made by management of a financial statement element, item or account in the financial statements. Accounting estimates in our historical consolidated financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. The accounting estimates described below require us to make assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that we could have used or changes in an accounting estimate that are reasonably likely to occur could have a material impact on the presentation of our financial condition or results of operations. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be predicted with certainty. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Our significant accounting policies are discussed in Note 2 to our consolidated financial statements. We believe the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the audit committee of the board of directors of CenterPoint Energy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INTANGIBLES

We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and annually for goodwill as required by SFAS No. 142, "Goodwill and Other Intangible Assets." No impairment of goodwill was indicated based on our analysis as of January 1, 2004. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, regulatory matters and operating costs could negatively affect the fair value of our assets and result in an impairment charge.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

UNBILLED REVENUES

Revenues related to the sale and/or delivery of natural gas are generally recorded when natural gas is delivered to customers. However, the determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of natural gas delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(n) to the consolidated financial statements, incorporated herein by reference, for a discussion of new accounting pronouncements that affect us.

OTHER SIGNIFICANT MATTERS

Pension Plan. As discussed in Note 7(a) to our consolidated financial statements, we participate in CenterPoint Energy's qualified non-contributory pension plan covering substantially all employees. Pension expense for 2005 is estimated to be $15 million based on an expected return on plan assets of 8.5% and a discount rate of 5.75% as of December 31, 2004. Pension expense for the year ended December 31, 2004 was $35 million. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension will impact our future pension expense. We cannot predict with certainty what these factors will be in the future.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IMPACT OF CHANGES IN INTEREST RATES AND ENERGY COMMODITY PRICES

We are exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in our consolidated financial statements. Most of the revenues and income from our business activities are impacted by market risks. Categories of market risk include exposure to commodity prices through non-trading activities, interest rates and equity prices. A description of each market risk is set forth below:

- Commodity price risk results from exposures to changes in spot prices, forward prices and price volatilities of commodities, such as natural gas and other energy commodities risk.

- Interest rate risk primarily results from exposures to changes in the level of borrowings and changes in interest rates.

- Equity price risk results from exposures to changes in prices of individual equity securities.

Management has established comprehensive risk management policies to monitor and manage these market risks. We manage these risk exposures through the implementation of our risk management policies and framework. We manage our exposures through the use of derivative financial instruments and derivative commodity instrument contracts. During the normal course of business, we review our hedging strategies and determine the hedging approach we deem appropriate based upon the circumstances of each situation.

Derivative instruments such as futures, forward contracts, swaps and options derive their value from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments that are listed and traded on an exchange.

Derivative transactions are entered into in our non-trading operations to manage and hedge certain exposures, such as exposure to changes in gas prices. We believe that the associated market risk of these instruments can best be understood relative to the underlying assets or risk being hedged.

INTEREST RATE RISK

We have outstanding long-term debt, mandatory redeemable preferred securities of a subsidiary trust holding solely our junior subordinated debentures (trust preferred securities), a bank facility and some lease obligations which subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $63 million at December 31, 2003. We had no floating-rate obligations at December 31, 2004.

At both December 31, 2003 and 2004, we had outstanding fixed-rate debt and trust preferred securities aggregating $2.4 billion in principal amount and having a fair value of $2.6 billion and $2.7 billion, respectively. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Note 6 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $59 million if interest rates were to decline by 10% from their levels at December 31, 2004. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity.

COMMODITY PRICE RISK FROM NON-TRADING ACTIVITIES

To reduce our commodity price risk from market fluctuations in the revenues derived from the sale of natural gas and related transportation, we enter into forward contracts, swaps and options (Non-Trading Energy Derivatives) in order to hedge some expected purchases of natural gas and sales of natural gas (a portion of which are firm commitments at the inception of the hedge). Non-Trading Energy Derivatives are also utilized to fix the price of future operational gas requirements.

We use derivative instruments as economic hedges to offset the commodity exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our Non-Trading Energy Derivatives using a sensitivity analysis. The sensitivity analysis performed on our Non-Trading Energy Derivatives measures the potential loss in earnings based on a hypothetical 10% movement in energy prices. A decrease of 10% in the market prices of energy commodities from their December 31, 2003 levels would have decreased the fair value of our Non-Trading Energy Derivatives by $50 million. A decrease of 10% in the market prices of energy commodities from their December 31, 2004 levels would have decreased the fair value of our Non-Trading Energy Derivatives by $46 million.

The above analysis of the Non-Trading Energy Derivatives utilized for hedging purposes does not include the favorable impact that the same hypothetical price movement would have on our physical purchases and sales of natural gas to which the hedges relate. Furthermore, the Non-Trading Energy Derivative portfolio is managed to complement the physical transaction portfolio, reducing overall risks within limits. Therefore, the adverse impact to the fair value of the portfolio of Non-Trading Energy Derivatives held for hedging 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 Non-Trading Energy Derivatives are not closed out in advance of their expected term;

- the Non-Trading Energy Derivatives continue to function effectively as hedges of the underlying risk; and

- as applicable, anticipated underlying transactions settle as expected.

If any of the above-mentioned assumptions ceases to be true, a loss on the derivative instruments may occur, or the options might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first. Non-Trading Energy Derivatives designated and effective as hedges, may still have some percentage which is not effective. The change in value of the Non-Trading Energy Derivatives that represents the ineffective component of the hedges is recorded in our results of operations.

CenterPoint Energy has established a Risk Oversight Committee, comprised of corporate and business segment officers, that oversees commodity price and credit risk activities, including trading, marketing, risk management services and hedging activities. The committee's duties are to establish commodity risk policies, allocate risk capital, approve trading of new products and commodities, monitor risk positions and ensure compliance with the risk management policies and procedures and trading limits established by CenterPoint Energy's board of directors.

Our policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

STATEMENTS OF CONSOLIDATED INCOME

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
	(IN THOUSANDS)		
REVENUES	$ 4,207,836	$ 5,649,720	$ 6,983,445
EXPENSES:			
Natural gas	2,900,682	4,296,928	5,524,451
Operation and maintenance	666,502	688,639	731,959
Depreciation and amortization	167,456	175,975	187,228
Taxes other than income taxes	119,911	129,846	146,891
Total	3,854,551	5,291,388	6,590,529
OPERATING INCOME	353,285	358,332	392,916
OTHER INCOME (EXPENSE):			
Interest and other finance charges	(153,713)	(178,985)	(178,185)
Other, net	8,131	8,237	15,875
Total	(145,582)	(170,748)	(162,310)
INCOME BEFORE INCOME TAXES	207,703	187,584	230,606
Income Tax Expense	(87,643)	(58,706)	(86,497)
NET INCOME	$ 120,060	$ 128,878	$ 144,109

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
		(IN THOUSANDS)	
Net income	$ 120,060	$ 128,878	$ 144,109
Other comprehensive income (loss), net of tax:			
Minimum non-qualified pension liability adjustment (net of tax of $790)	1,468	--	--
Net deferred gain (loss) from cash flow hedges (net of tax of $35,142, $15,405 and $30,740)	46,062	21,971	59,104
Reclassification of net deferred loss (gain) from cash flow hedges realized in net income (net of tax of $5,681, $569 and $12,236)	381	1,297	(23,403)
Reclassification of deferred gain from de-designation of cash flow hedges to over/under recovery of gas costs (net of tax of $36,766)	--	--	(68,280)
Other comprehensive income (loss)	47,911	23,268	(32,579)
Comprehensive income	$ 167,971	$ 152,146	$ 111,530

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

CONSOLIDATED BALANCE SHEETS

	DECEMBER 31, 2003	DECEMBER 31, 2004
	(IN THOUSANDS)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 34,447	$ 140,466
Accounts receivable, net	462,988	612,708
Accrued unbilled revenue	323,844	502,163
Accounts and notes receivable -- affiliated companies, net	--	11,987
Inventory	187,226	199,249
Non-trading derivative assets	45,897	50,219
Taxes receivable	32,023	155,155
Deferred tax asset	--	12,256
Prepaid expenses	11,104	8,308
Other	71,597	92,160
Total current assets	1,169,126	1,784,671
PROPERTY, PLANT AND EQUIPMENT, NET	3,735,561	3,834,083
OTHER ASSETS:		
Goodwill, net	1,740,510	1,740,510
Other intangibles, net	20,101	19,719
Non-trading derivative assets	11,273	17,682
Accounts and notes receivable -- affiliated companies, net	33,929	18,197
Other	142,162	118,089
Total other assets	1,947,975	1,914,197
TOTAL ASSETS	$ 6,852,662	$ 7,532,951
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Short-term borrowings	$ 63,000	$ --
Current portion of long-term debt	--	366,873
Accounts payable	528,394	798,661
Accounts and notes payable -- affiliated companies, net	23,351	--
Taxes accrued	65,636	77,802
Interest accrued	58,505	57,741
Customer deposits	58,372	60,164
Non-trading derivative liabilities	6,537	26,323
Accumulated deferred income taxes, net	8,856	--
Other	125,132	272,996
Total current liabilities	937,783	1,660,560
OTHER LIABILITIES:		
Accumulated deferred income taxes, net	645,125	640,780
Non-trading derivative liabilities	3,330	6,412
Benefit obligations	130,980	128,537
Other	571,005	556,819
Total other liabilities	1,350,440	1,332,548
LONG-TERM DEBT	2,370,974	2,000,696
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
STOCKHOLDER'S EQUITY	2,193,465	2,539,147
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$ 6,852,662	$ 7,532,951

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

STATEMENTS OF CONSOLIDATED CASH FLOWS

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
	(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 120,060	$ 128,878	$ 144,109
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	167,456	175,975	187,228
Deferred income taxes	23,003	25,097	(8,332)
Amortization of deferred financing costs	2,770	8,424	9,618
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	3,275	(121,864)	(230,119)
Accounts receivable/payable, affiliates	(65,688)	(3,784)	6,519
Inventory	8,762	(51,519)	(12,023)
Taxes receivable	(61,512)	29,489	118,387
Accounts payable	198,045	58,062	273,797
Fuel cost recovery	28,317	25,420	25,212
Interest and taxes accrued	7,653	18,000	11,402
Net non-trading derivative assets and liabilities	13,527	17,828	(38,964)
Other current assets	(32,833)	(36,998)	(17,783)
Other current liabilities	11,604	(1,268)	(20,332)
Other assets	100,118	19,663	47,224
Other liabilities	(92,064)	40,250	(6,454)
Other, net	1,370	(14,481)	(3,405)
Net cash provided by operating activities	433,863	317,172	486,084
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(266,208)	(265,061)	(269,395)
Decrease (increase) in affiliate notes receivable	96,562	5,168	(30,322)
Other, net	9,726	(7,581)	(3,163)
Net cash used in investing activities	(159,920)	(267,474)	(302,880)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments of long-term debt	(6,653)	(507,795)	--
Proceeds from long-term debt	--	928,525	--
Increase (decrease) in short-term borrowings, net	1,473	(284,000)	(63,000)
Increase (decrease) in notes with affiliates, net	74,096	(74,096)	--
Dividends to parent	(350,000)	--	(12,500)
Debt issuance costs	--	(87,122)	(1,685)
Other, net	(47)	--	--
Net cash used in financing activities	(281,131)	(24,488)	(77,185)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(7,188)	25,210	106,019
CASH AND CASH EQUIVALENTS AT BEGINNING OF THE YEAR	16,425	9,237	34,447
CASH AND CASH EQUIVALENTS AT END OF THE YEAR	$ 9,237	$ 34,447	$ 140,466
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash Payments:			
Interest	$ 146,244	$ 164,040	$ 175,871
Income taxes (refunds)	125,085	(49,033)	41,846

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

STATEMENTS OF CONSOLIDATED STOCKHOLDER'S EQUITY

	2002		2003		2004	
	SHARES	AMOUNT	SHARES	AMOUNT	SHARES	AMOUNT
	(IN THOUSANDS OF DOLLARS AND SHARES)					
COMMON STOCK						
Balance, beginning of year	1,000	$ 1	1,000	$ 1	1,000	$ 1
Balance, end of year	1,000	1	1,000	1	1,000	1
ADDITIONAL PAID-IN-CAPITAL						
Balance, beginning of year		2,255,395		1,986,364		1,985,254
Dividend to parent		(272,907)		--		--
Contributions from parent		3,876		--		246,652
Other		--		(1,110)		--
Balance, end of year		1,986,364		1,985,254		2,231,906
RETAINED EARNINGS						
Balance, beginning of year		1,837		44,804		173,682
Net income		120,060		128,878		144,109
Dividend to parent		(77,093)		--		(12,500)
Balance, end of year		44,804		173,682		305,291
ACCUMULATED OTHER COMPREHENSIVE INCOME						
Balance, end of year:						
Net deferred gain from cash flow hedges		11,260		34,528		1,949
Total accumulated other comprehensive income, end of year		11,260		34,528		1,949
Total Stockholder's Equity		$ 2,042,429		$ 2,193,465		$ 2,539,147

See Notes to the Company's Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BACKGROUND AND BASIS OF PRESENTATION

CenterPoint Energy Resources Corp. (CERC Corp., and, together with its subsidiaries, the Company), owns and operates natural gas distribution facilities, interstate pipelines and natural gas gathering, processing and treating facilities. CERC Corp. is a Delaware corporation.

The Company's operations of its local distribution companies are conducted by three unincorporated divisions: Houston Gas, Minnesota Gas and Southern Gas Operations. In 2004, the naming conventions of the Company's three unincorporated divisions were changed in an effort to increase brand recognition. CenterPoint Energy Arkla and the portion of CenterPoint Energy Entex (Entex) located outside of the metropolitan Houston area were renamed Southern Gas Operations. The metropolitan Houston portion of Entex was renamed Houston Gas, and CenterPoint Energy Minnegasco was renamed Minnesota Gas. Through wholly owned subsidiaries, the Company owns two interstate natural gas pipelines and gas gathering systems, provides various ancillary services, and offers variable and fixed price physical natural gas supplies to commercial and industrial customers and natural gas distributors.

The Company is an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company created on August 31, 2002, as part of a corporate restructuring of Reliant Energy, Incorporated (Reliant Energy). CenterPoint Energy is a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (1935 Act). The 1935 Act and related rules and regulations impose a number of restrictions on the activities of CenterPoint Energy and those of its regulated subsidiaries. The 1935 Act, among other things, limits the ability of CenterPoint Energy and its regulated subsidiaries to issue debt and equity securities without prior authorization, restricts the source of dividend payments to current and retained earnings without prior authorization, regulates sales and acquisitions of certain assets and businesses and governs affiliated service, sales and construction contracts.

Basis of Presentation

The Company's reportable business segments include the following: Natural Gas Distribution, Pipelines and Gathering and Other Operations. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers and non-rate regulated retail gas marketing operations for commercial and industrial customers. Pipelines and Gathering includes the interstate natural gas pipeline operations and the natural gas gathering and pipeline services businesses. Other Operations consists primarily of other corporate operations which support all of the Company's business operations.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) RECLASSIFICATIONS AND USE OF ESTIMATES

Some amounts from the previous years have been reclassified to conform to the 2004 presentation of financial statements. These reclassifications do not affect net income.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(b) PRINCIPLES OF CONSOLIDATION

The accounts of CERC Corp. and its wholly owned and majority owned subsidiaries are included in the Company's consolidated financial statements. All significant intercompany transactions and balances are eliminated in consolidation. The Company uses the equity method of accounting for investments in entities in which the Company has an ownership interest between 20% and 50% and exercises significant influence. Other investments, excluding marketable securities, are carried at cost.

(c) REVENUES

The Company records revenue for natural gas sales and services under the accrual method and these revenues are recognized upon delivery to customers. Natural gas sales not billed by month-end are accrued based upon estimated purchased gas volumes, estimated lost and unaccounted for gas and currently effective tariff rates. The Pipelines and Gathering business segment records revenues as transportation services are provided.

(d) LONG-LIVED ASSETS AND INTANGIBLES

The Company records property, plant and equipment at historical cost. The Company expenses repair and maintenance costs as incurred. Property, plant and equipment includes the following:

	ESTIMATED USEFUL LIVES (YEARS)	DECEMBER 31, 2003	DECEMBER 31, 2004
		(IN MILLIONS)	
Natural gas distribution	5-50	$ 2,316	$ 2,494
Pipelines and gathering	5-75	1,722	1,767
Other property	3-40	49	35
Total		4,087	4,296
Accumulated depreciation		(351)	(462)
Property, plant and equipment, net		$ 3,736	$ 3,834

The components of the Company's other intangible assets consist of the following:

	DECEMBER 31, 2003 CARRYING AMOUNT	DECEMBER 31, 2003 ACCUMULATED AMORTIZATION	DECEMBER 31, 2004 CARRYING AMOUNT	DECEMBER 31, 2004 ACCUMULATED AMORTIZATION
	(IN MILLIONS)			
Land Use Rights	$ 7	$ (3)	$ 7	$ (3)
Other	20	(4)	21	(5)
Total	$ 27	$ (7)	$ 28	$ (8)

The Company recognizes specifically identifiable intangibles, including land use rights and permits, when specific rights and contracts are acquired. The Company has no intangible assets with indefinite lives recorded as of December 31, 2004 other than goodwill discussed below. The Company amortizes other acquired intangibles on a straight-line basis over the lesser of their contractual or estimated useful lives that range from 47 to 75 years for land rights and 4 to 25 years for other intangibles.

Amortization expense for other intangibles for the years ended December 2002, 2003 and 2004 was $1 million, $2 million and $2 million, respectively. Estimated amortization expense is approximately $2 million per year for the five succeeding fiscal years.

Goodwill by reportable business segment is as follows (in millions):

	DECEMBER 31, 2003 AND 2004
Natural Gas Distribution	$ 1,085
Pipelines and Gathering	601
Other Operations	55
Total	$ 1,741

The Company completed its annual evaluation of goodwill for impairment as of January 1, 2004 and no impairment was indicated.

The Company periodically evaluates long-lived assets, including property, plant and equipment, goodwill and specifically identifiable intangibles, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. A resulting impairment loss is highly dependent on these underlying assumptions.

(e) REGULATORY ASSETS AND LIABILITIES

The Company applies the accounting policies established in SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71) to the accounts of the utility operations of the Natural Gas Distribution business segment and to some of the accounts of the Pipelines and Gathering business segment.

The following is a list of regulatory assets/liabilities reflected on the Company's Consolidated Balance Sheets as of December 31, 2003 and 2004:

	DECEMBER 31, 2003	DECEMBER 31, 2004
	(IN MILLIONS)	
Regulatory assets in other long-term assets..............	$ 34	$ 21
Regulatory liabilities in other long-term liabilities.....	(434)	(433)
Total...	$ (400)	$ (412)

If events were to occur that would make the recovery of these assets and liabilities no longer probable, the Company would be required to write-off or write-down these regulatory assets and liabilities.

The Company's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2003 and 2004, these removal costs of $415 million and $428 million, respectively, are classified as regulatory liabilities in the Consolidated Balance Sheets. The Company has also identified other asset retirement obligations that cannot be estimated because the assets associated with the retirement obligations have an indeterminate life.

(f) DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Other amortization expense includes amortization of regulatory assets and other intangibles.

The following table presents depreciation and other amortization expense for 2002, 2003 and 2004.

	YEAR ENDED DECEMBER 31, 2002	2003	2004
		(IN MILLIONS)	
Depreciation expense.....................................	$ 153	$ 161	$ 171
Other amortization expense...............................	14	15	16
Total depreciation and amortization expense............	$ 167	$ 176	$ 187

(g) CAPITALIZATION OF INTEREST AND ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash through depreciation provisions included in rates for subsidiaries that apply SFAS No. 71. Interest and AFUDC for subsidiaries that apply SFAS No. 71 are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During 2002, 2003 and 2004, the Company capitalized interest and AFUDC of $1 million, $1 million and $2 million, respectively.

(h) INCOME TAXES

The Company is included in the consolidated income tax returns of CenterPoint Energy. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. Pursuant to the tax sharing agreement with CenterPoint Energy, in 2004, the Company received an allocation of CenterPoint Energy's tax benefits totaling $171 million. The Company uses the liability method of accounting for deferred income taxes and measures deferred income taxes for all significant income tax temporary differences. Investment tax credits were deferred and are being amortized over the estimated lives of the related property. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy. For additional information regarding income taxes, see Note 8.

(i) ACCOUNTS RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

Accounts receivable are net of an allowance for doubtful accounts of $28 million at December 31, 2003 and 2004. The provision for doubtful accounts in the Company's Statements of Consolidated Income for 2002, 2003 and 2004 was $15 million, $24 million and $26 million, respectively.

In connection with the Company's November 2002 amendment and extension of its $150 million receivables facility, CERC Corp. formed a bankruptcy remote subsidiary for the sole purpose of buying receivables created by the Company and selling those receivables to an unrelated third-party. This transaction was accounted for as a sale of receivables under the provisions of SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," (SFAS No. 140) and, as a result, the related receivables are excluded from the Consolidated Balance Sheets. The bankruptcy remote subsidiary purchases receivables with cash and subordinated notes. In July 2003, the subordinated notes owned by the Company were pledged to a gas supplier to secure obligations incurred in connection with the purchase of gas by the Company. Effective June 25, 2003, the Company reduced the purchase limit under the receivables facility from $150 million to $100 million. As of December 31, 2003, the Company had utilized $100 million of its receivables facility.

In the first quarter of 2004, the Company replaced the receivables facility with a $250 million committed one-year receivables facility. The bankruptcy remote subsidiary continues to buy the Company's receivables and sell them to an unrelated third-party, which transactions are accounted for as a sale of receivables under SFAS No. 140. As of December 31, 2004, the Company had utilized $181 million of its receivables facility.

The average outstanding balances on the receivables facilities were $16 million, $100 million and $190 million in 2002, 2003 and 2004, respectively. Sales of receivables were approximately $0.2 billion, $1.2 billion and $2.4 billion in 2002, 2003 and 2004.

(j) INVENTORY

Inventory consists principally of materials and supplies and natural gas. Inventories used in the retail natural gas distribution operations are primarily valued at the lower of average cost or market.

	DECEMBER 31,	
	2003	2004
	(IN MILLIONS)	
Materials and supplies	$ 27	$ 25
Natural gas	160	174
Total inventory	$ 187	$ 199

(k) INVESTMENT IN OTHER DEBT AND EQUITY SECURITIES

In accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), the Company reports "available-for-sale" securities at estimated fair value within other long-term assets in the Company's Consolidated Balance Sheets and any unrealized gain or loss, net of tax, as a separate component of stockholders' equity and accumulated other comprehensive income. In accordance with SFAS No. 115, the Company reports "trading" securities at estimated fair value in the Company's Consolidated Balance Sheets, and any unrealized holding gains and losses are recorded as other income (expense) in the Company's Statements of Consolidated Income.

As of December 31, 2003 and 2004, the Company held no "available-for-sale" or "trading" securities.

(l) ENVIRONMENTAL COSTS

The Company expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Company expenses amounts that relate to an existing condition caused by past operations, and that do not have future economic benefit. The Company records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(m) STATEMENTS OF CONSOLIDATED CASH FLOWS

For purposes of reporting cash flows, the Company considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase.

(n) NEW ACCOUNTING PRONOUNCEMENTS

In January 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. (FIN) 46 "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" (FIN 46). FIN 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. On December 24, 2003, the FASB issued a revision to FIN 46 (FIN 46-R). For special-purpose entities (SPEs) created before February 1, 2003, the Company applied the provisions of FIN 46 or FIN 46-R as of December 31, 2003. FIN 46-R is effective for all other entities for financial periods ending after March 15, 2004. The Company has a subsidiary trust that has Mandatorily Redeemable Preferred Securities outstanding. The trust was determined to be a variable interest entity under FIN 46-R and the Company also determined that it is not the primary beneficiary of the trust. As of December 31, 2003, the Company deconsolidated the trust and instead reports its junior subordinated debentures due to the trust as long-term debt.

On May 19, 2004, the FASB issued a FASB Staff Position (FSP) addressing the appropriate accounting and disclosure requirements for companies that sponsor a postretirement health care plan that provides prescription drug benefits. The new guidance from the FASB was deemed necessary as a result of the 2003 Medicare prescription law, which includes a federal subsidy for qualifying companies. FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-2), requires that the effects of the federal subsidy be considered an actuarial gain and treated like similar gains and losses and requires certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. The FASB's related existing guidance, FSP 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," was superseded upon the effective date of FSP 106-2. The Company adopted FSP 106-2 prospectively in July 2004 with no material effect on its results of operations, financial condition or cash flows.

3. REGULATORY MATTERS

(a) RATE CASES

In 2004, the City of Houston, 28 other cities and the Railroad Commission of Texas (Railroad Commission) approved a settlement that increased Houston Gas' base rate and service charge revenues by approximately $14 million annually.

In February 2004, the Louisiana Public Service Commission (LPSC) approved a settlement that increased Southern Gas Operations' base rate and service charge revenues in its South Louisiana Division by approximately $2 million annually.

In July 2004, Minnesota Gas filed an application for a general rate increase of $22 million with the Minnesota Public Utilities Commission (MPUC). Minnesota Gas and the Minnesota Department of Commerce have agreed to a settlement of all issues, including an annualized increase in the amount of $9 million, subject to approval by the MPUC. A final decision on this rate relief request is expected from the MPUC in the second quarter of 2005. Interim rates of $17 million on an annualized basis became effective on October 1, 2004, subject to refund.

In July 2004, the LPSC approved a settlement that increased Southern Gas Operations' base rate and service charge revenues in its North Louisiana Division by approximately $7 million annually.

In October 2004, Southern Gas Operations filed an application for a general rate increase of approximately $3 million with the Railroad Commission for rate relief in the unincorporated areas of its Beaumont, East Texas and South Texas Divisions. The Railroad Commission staff has begun its review of the request, and a decision is anticipated in April 2005.

In November 2004, Southern Gas Operations filed an application for a general rate increase of approximately $34 million with the Arkansas Public Service Commission (APSC). The APSC staff has begun its review of the request, and a decision is anticipated in the second half of 2005.

In December 2004, the Oklahoma Corporation Commission approved a settlement that increased Southern Gas Operations' base rate and service charge revenues in Oklahoma by approximately $3 million annually.

(b) CITY OF TYLER, TEXAS DISPUTE

In July 2002, the City of Tyler, Texas, asserted that Southern Gas Operations had overcharged residential and small commercial customers in that city for gas costs under supply agreements in effect since 1992. That dispute has been referred to the Railroad Commission by agreement of the parties for a determination of whether Southern Gas Operations has properly charged and collected for gas service to its residential and commercial customers in its Tyler distribution system in accordance with lawful filed tariffs during the period beginning November 1, 1992, and ending October 31, 2002. In December 2004, the Railroad Commission conducted a hearing on the matter and is expected to issue a ruling in March or April of 2005. In a parallel action now in the Court of Appeals in Austin, Southern Gas Operations is challenging the scope of the Railroad Commission's inquiry which goes beyond the issue of whether Southern Gas Operations had properly followed its tariffs to include a review of Southern Gas Operations' historical gas purchases. The Company believes such a review is not permitted by law and is beyond what the parties requested in the joint petition that initiated the proceeding at the Railroad Commission. The Company believes that all costs for Southern Gas Operations' Tyler distribution system have been properly included and recovered from customers pursuant to Southern Gas Operations' filed tariffs.

4. RELATED PARTY TRANSACTIONS

The following table summarizes receivables from, or payables to, CenterPoint Energy or its subsidiaries:

	DECEMBER 31, 2003	DECEMBER 31, 2004
	(IN MILLIONS)	
Accounts receivable from affiliates	$ 6	$ 4
Accounts payable to affiliates	(29)	(34)
Note receivable from affiliates(1)	--	42
Accounts and notes receivable/(payable)-- affiliated companies, net	$ (23)	$ 12
Long-term accounts receivable from affiliates	$ --	$ 64
Long-term accounts payable to affiliates	--	(45)
Long-term notes receivable from affiliates	67	--
Long-term notes payable to affiliates	(33)	(1)
Long-term accounts and notes receivable -- affiliated companies, net	$ 34	$ 18

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(1) This note represents money pool investments.

For the years ended December 31, 2002, 2003 and 2004, the Company had net interest income (expense) related to affiliate borrowings of $(2) million, $3 million and $9 million, respectively.

The 1935 Act generally prohibits borrowings by CenterPoint Energy from its subsidiaries, including the Company, either through the money pool or otherwise.

During 2002, the sales and services by the Company to Reliant Resources, Inc., (now named Reliant Energy, Inc.) (RRI), a former affiliate, totaled $42 million. During 2002, 2003 and 2004, the sales and services by the Company to Texas Genco Holdings, Inc. (Texas Genco) totaled $28 million, $31 million and $22 million, respectively.

CenterPoint Energy provides some corporate services to the Company. The costs of services have been charged directly to the Company using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment, and proportionate corporate formulas based on assets, operating expenses and employees. These charges are not necessarily indicative of what would have been incurred had the Company not been an affiliate. Amounts charged to the Company for these services were $107 million, $113 million and $116 million for 2002, 2003 and 2004, respectively, and are included primarily in operation and maintenance expenses.

In 2004, the Company paid a dividend of $12.5 million to Utility Holding, LLC.

5. DERIVATIVE INSTRUMENTS

The Company is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. The Company utilizes derivative financial instruments such as physical forward contracts, swaps and options (Energy Derivatives) to mitigate the impact of changes in its natural gas businesses on its operating results and cash flows.

(a) NON-TRADING ACTIVITIES

Cash Flow Hedges. To reduce the risk from market fluctuations associated with purchased gas costs, the Company enters into energy derivatives in order to hedge certain expected purchases and sales of natural gas (non-trading energy derivatives). The Company applies hedge accounting for its non-trading energy derivatives utilized in non-trading activities only if there is a high correlation between price movements in the derivative and the item designated as being hedged. The Company analyzes its physical transaction portfolio to determine its net exposure by delivery location and delivery period. Because the Company's physical transactions with similar delivery locations and periods are highly correlated and share similar risk exposures, the Company facilitates hedging for customers by aggregating physical transactions and subsequently entering into non-trading energy derivatives to mitigate exposures created by the physical positions.

During 2004, hedge ineffectiveness of $0.4 million was recognized in earnings from derivatives that are designated and qualify as Cash Flow Hedges, and in 2003 and 2002, no hedge ineffectiveness was recognized. No component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness. If it becomes probable that an anticipated transaction will not occur, the Company realizes in net income the deferred gains and losses recognized in accumulated other comprehensive loss. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in the Company's Statements of Consolidated Income under the caption "Natural Gas." Cash flows resulting from these transactions in non-trading energy derivatives are included in the Statements of Consolidated Cash Flows in the same category as the item being hedged. As of December 31, 2004, the Company expects $5 million in accumulated other comprehensive income to be reclassified into net income during the next twelve months.

The maximum length of time the Company is hedging its exposure to the variability in future cash flows for forecasted transactions on existing financial instruments is primarily two years with a limited amount of exposure up to five years. The Company's policy is not to exceed five years in hedging its exposure.

Other Derivative Financial Instruments. The Company also has natural gas contracts which are derivatives which are not hedged. Load following services that the Company offers its natural gas customers create an inherent tendency to be either long or short natural gas supplies relative to customer purchase commitments. The Company measures and values all of its volumetric imbalances on a real time basis to minimize its exposure to commodity price and volume risk. The aggregate Value at Risk (VaR) associated with these operations is calculated daily and averaged $0.2 million with a high of $1 million during 2004. The Company does not engage in proprietary or speculative commodity trading. Unhedged positions are accounted for by adjusting the carrying amount of the contracts to market and recognizing any gain or loss in operating income, net. During 2004, the Company recognized net gains related to unhedged positions amounting to $7 million and as of December 31, 2004 had recorded short-term risk management assets and liabilities of $4 million and $5 million, respectively, included in other current assets and other current liabilities, respectively.

(b) CREDIT RISKS

In addition to the risk associated with price movements, credit risk is also inherent in the Company's non-trading derivative activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. The following table shows the composition of the non-trading derivative assets of the Company as of December 31, 2003 and 2004 (in millions):

	DECEMBER 31, 2003		DECEMBER 31, 2004	
	INVESTMENT GRADE(1)(2)	TOTAL	INVESTMENT GRADE(1)(2)	TOTAL(3)
Energy marketers	$ 24	$ 35	$ 10	$ 17
Financial institutions	21	21	50	50
Other	--	1	1	1
Total	$ 45	$ 57	$ 61	$ 68

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(1) "Investment grade" is primarily determined using publicly available credit ratings along with the consideration of credit support (such as parent company guarantees) and collateral, which encompass cash and standby letters of credit.

(2) For unrated counterparties, the Company performs financial statement analysis, considering contractual rights and restrictions and collateral, to create a synthetic credit rating.

(3) The $17 million non-trading derivative asset includes a $6 million asset due to trades with Reliant Energy Services, Inc. (Reliant Energy Services), a former affiliate. As of December 31, 2004, Reliant Energy Services did not have an investment grade rating.

(c) GENERAL POLICY

CenterPoint Energy has established a Risk Oversight Committee composed of corporate and business segment officers that oversees all commodity price and credit risk activities, including the Company's trading, marketing, risk management services and hedging activities. The committee's duties are to establish the Company's commodity risk policies, allocate risk capital within limits established by CenterPoint Energy's board of directors, approve trading of new products and commodities, monitor risk positions and ensure compliance with the Company's risk management policies and procedures and trading limits established by the CenterPoint Energy's board of directors.

The Company's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

6. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

	DECEMBER 31, 2003		DECEMBER 31, 2004	
	LONG-TERM	CURRENT(1)	LONG-TERM	CURRENT(1)
	(IN MILLIONS)			
Short-term borrowings:				
Revolving credit facility		$ 63		$ --
Long-term debt:				
Convertible subordinated debentures 6.00% due 2012	74	--	69	6
Senior notes 5.95% to 8.90% due 2005 to 2014	2,251	--	1,923	325
Junior subordinated debentures payable to affiliate 6.25% due 2026(2)	6	--	6	--
Other	36	--	--	36
Unamortized discount and premium(3)	4	--	3	--
Total long-term debt	2,371	--	2,001	367
Total borrowings	$ 2,371	$ 63	$ 2,001	$ 367

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(1) Includes amounts due within one year of the date noted.

(2) The junior subordinated debentures were issued to a subsidiary trust in connection with the issuance by that trust of preferred securities. The trust preferred securities were deconsolidated effective December 31, 2003 pursuant to the adoption of FIN 46. This resulted in the junior subordinated debentures held by the trust being reported as long-term debt. For further discussion, see Note 2(n).

(3) Debt acquired in business acquisitions is adjusted to fair market value as of the acquisition date. Included in long-term debt is additional unamortized premium related to fair value adjustments of long-term debt of $6 million and $5 million at December 31, 2003 and 2004, respectively, which is being amortized over the remaining term of the related long-term debt.

(a) SHORT-TERM BORROWINGS

Credit Facilities. As of December 31, 2003, the Company had a revolving credit facility that provided for an aggregate of $200 million in committed credit. As of December 31, 2003, $63 million was borrowed under the revolving credit facility. This facility terminated in March 2004. The weighted average interest rate on short-term borrowings at December 31, 2003 was 5.0%, excluding facility fees and other fees paid in connection with the arrangement of the bank facilities.

(b) LONG-TERM DEBT

As of December 31, 2004, the Company had a revolving credit facility that provided for an aggregate of $250 million in committed credit. The revolving credit facility terminates on March 23, 2007. Fully-drawn rates for borrowings under this facility, including the facility fee, are London inter-bank offered rate (LIBOR) plus 150 basis points based on current credit ratings and the applicable pricing grid. As of December 31, 2004, such credit facility was not utilized.

Junior Subordinated Debentures (Trust Preferred Securities). In June 1996, a Delaware statutory business trust created by CERC Corp. (CERC Trust) issued $173 million aggregate amount of convertible preferred securities to the public. CERC Trust used the proceeds of the offering to purchase convertible junior subordinated debentures issued by CERC Corp. having an interest rate and maturity date that correspond to the distribution rate and mandatory redemption date of the convertible preferred securities. The convertible junior subordinated debentures represent CERC Trust's sole asset and its entire operations. CERC Corp. considers its obligation under the Amended and Restated Declaration of Trust, Indenture and Guaranty Agreement relating to the convertible preferred securities, taken together, to constitute a full and unconditional guarantee by CERC Corp. of CERC Trust's obligations with respect to the convertible preferred securities. As discussed in Note 2(n), upon the Company's adoption of FIN 46, the junior subordinated debentures discussed above were included in long-term debt as of December 31, 2003 and 2004.

The convertible preferred securities are mandatorily redeemable upon the repayment of the convertible junior subordinated debentures at their stated maturity or earlier redemption. Effective January 7, 2003, the convertible preferred securities are convertible at the option of the holder into $33.62 of cash and 2.34 shares of CenterPoint Energy common stock for each $50 of liquidation value. As of December 31, 2003 and 2004, the liquidation amount of convertible preferred securities outstanding was $0.4 million and $0.3 million, respectively. The securities, and their underlying convertible junior subordinated debentures, bear interest at 6.25% and mature in June 2026. Subject to some limitations, CERC Corp. has the option of deferring payments of interest on the convertible junior subordinated debentures. During any deferral or event of default, CERC Corp. may not pay dividends on its common stock to CenterPoint Energy. As of December 31, 2004, no interest payments on the convertible junior subordinated debentures had been deferred.

Maturities. The Company's consolidated maturities of long-term debt and sinking fund requirements are $367 million in 2005, $158 million in 2006, $7 million in 2007, $307 million in 2008 and $7 million in 2009. The 2005 amount is net of the portion of a sinking fund payment that can be satisfied with debt that had been acquired and retired as of December 31, 2004.

(c) RECEIVABLES FACILITY

On January 21, 2004, the Company replaced its $100 million receivables facility with a $250 million receivables facility. As of December 31, 2004, the Company had $181 million outstanding under its receivables facility. In January 2005, the facility was extended to January 2006 and temporarily increased, for the period from January 2005 to June 2005, to $375 million to provide additional liquidity to the Company during the peak heating season of 2005, in view of recent levels of, and volatility in, gas prices.

7. EMPLOYEE BENEFIT PLANS

(a) PENSION PLANS

Substantially all of the Company's employees participate in CenterPoint Energy's qualified non-contributory pension plan. Under the cash balance formula, participants accumulate a retirement benefit based upon 4% of eligible earnings and accrued interest. Prior to 1999, the pension plan accrued benefits based on years of service, final average pay and covered compensation. As a result, certain employees participating in the plan as of December 31, 1998 are eligible to receive the greater of the accrued benefit calculated under the prior plan through 2008 or the cash balance formula.

CenterPoint Energy's funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Pension expense is allocated to the Company based on covered employees. This calculation is intended to allocate pension costs in the same manner as a separate employer plan. Assets of the plan are not segregated or restricted by CenterPoint Energy's participating subsidiaries. The Company recognized pension expense of $13 million, $36 million and $35 million for the years ended December 31, 2002, 2003 and 2004, respectively.

In addition to the Plan, the Company participates in CenterPoint Energy's non-qualified benefit restoration plan, which allows participants to retain the benefits to which they would have been entitled under the qualified pension plan except for federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. The expense associated with the non-qualified pension plan was $2 million, $3 million and less than $1 million for the years ended December 31, 2002, 2003 and 2004, respectively.

(b) SAVINGS PLAN

The Company participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 16% of compensation. CenterPoint Energy matches 75% of the first 6% of each employee's compensation contributed. CenterPoint Energy may contribute an additional discretionary match of up to 50% of the first 6% of each employee's compensation contributed. These matching contributions are fully vested at all times. CenterPoint Energy allocates to the Company the savings plan benefit expense related to the Company's employees.

Savings plan benefit expense was $17 million, $15 million and $16 million for the years ended December 31, 2002, 2003 and 2004, respectively.

(c) POSTRETIREMENT BENEFITS

The Company's employees participate in CenterPoint Energy's plans which provide certain healthcare and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Under plan amendments effective in early 1999, healthcare benefits for future retirees were changed to limit employer contributions for medical coverage. Such benefit costs are accrued over the active service period of employees.

The Company is required to fund a portion of its obligations in accordance with rate orders. All other obligations are funded on a pay-as-you-go basis.

The net postretirement benefit cost includes the following components:

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
	(IN MILLIONS)		
Service cost--benefits earned during the period	$ 2	$ 2	$ 2
Interest cost on projected benefit obligation	9	10	10
Expected return on plan assets	(2)	(2)	(2)
Net amortization	2	2	2
Other	-	-	1
Net postretirement benefit cost	$ 11	$ 12	$ 13

The Company used the following assumptions to determine net postretirement benefit costs:

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
Discount rate	7.25%	6.75%	6.25%
Expected return on plan assets	9.5%	9.0%	8.5%

In determining net periodic benefits cost, the Company uses fair value, as of the beginning of the year, as its basis for determining expected return on plan assets.

Following are reconciliations of the Company's beginning and ending balances of its postretirement benefit plans benefit obligation, plan assets and funded status for 2003 and 2004.

	YEAR ENDED DECEMBER 31, 2003	YEAR ENDED DECEMBER 31, 2004
	(IN MILLIONS)	
CHANGE IN BENEFIT OBLIGATION		
Accumulated benefit obligation, beginning of year	$ 155	$ 171
Service cost	2	2
Interest cost	10	10
Benefit enhancement	--	1
Benefits paid	(18)	(21)
Participant contributions	4	4
Plan amendments	(2)	-
Actuarial loss	20	7
Accumulated benefit obligation, end of year	$ 171	$ 174
CHANGE IN PLAN ASSETS		
Plan assets, beginning of year	$ 18	$ 21
Benefits paid	(18)	(21)
Employer contributions	14	14
Participant contributions	4	4
Actual investment return	3	3
Plan assets, end of year	$ 21	$ 21
RECONCILIATION OF FUNDED STATUS		
Funded status	$ (150)	$ (153)
Unrecognized prior service cost	15	13
Unrecognized actuarial loss	40	46
Net amount recognized	$ (95)	$ (94)
AMOUNTS RECOGNIZED IN BALANCE SHEETS		
Benefit obligations	$ (95)	$ (94)
Net amount recognized at end of year	$ (95)	$ (94)
ACTUARIAL ASSUMPTIONS		
Discount rate	6.25%	5.75%
Expected long-term return on assets	8.5%	8.0%
Healthcare cost trend rate assumed for the next year	10.50%	9.75%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.5%	5.5%
Year that the rate reaches the ultimate trend rate	2011	2011
Measurement date used to determine plan obligations and assets	December 31, 2003	December 31, 2004

Assumed healthcare cost trend rates have a significant effect on the reported amounts for the Company's postretirement benefit plans. A 1% change in the assumed healthcare cost trend rate would have the following effects:

	1% INCREASE	1% DECREASE
	(IN MILLIONS)	
Effect on total of service and interest cost	$ -	$ -
Effect on the postretirement benefit obligation	6	5

The following table displays the weighted average asset allocations as of December 31, 2003 and 2004 for the Company's postretirement benefit plan:

	DECEMBER 31, 2003	DECEMBER 31, 2004
Domestic equity securities	40%	38%
International equity securities	10	11
Debt securities	49	50
Cash	1	1
Total	100%	100%

In managing the investments associated with the postretirement benefit plan, the Company's objective is to preserve and enhance the value of plan assets while maintaining an acceptable level of volatility. These objectives are expected to be achieved through an investment strategy, which manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, the Company has adopted and maintains the following asset allocation ranges for its postretirement benefit plan:

Domestic equity securities	33-43%
International equity securities	5-15%
Debt securities	48-58%
Cash	0-2%

The expected rate of return assumption was developed by reviewing the targeted asset allocations and historical index performance of the applicable asset classes over a 15-year period, adjusted for investment fees and diversification effects.

The Company expects to contribute $16 million to its postretirement benefits plan in 2005.

The following benefit payments are expected to be paid by the pension and postretirement benefit plans:

	POSTRETIREMENT BENEFITS (IN MILLIONS)
2005	$ 17
2006	18
2007	19
2008	20
2009	21
2010-2014	108

(d) POSTEMPLOYMENT BENEFITS

The Company participates in CenterPoint Energy's plan which provides postemployment benefits for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). Postemployment benefits costs were $6 million, $5 million and $3 million in 2002, 2003 and 2004, respectively.

(e) OTHER NON-QUALIFIED PLANS

The Company participates in CenterPoint Energy's deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of the Company. During 2002, 2003 and 2004, the Company recorded benefits expense relating to these programs of $1 million each year. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2003 and 2004, was $10 million and $9 million, respectively, relating to deferred compensation plans.

(f) OTHER EMPLOYEE MATTERS

As of December 31, 2004, approximately 30% of the Company's employees are subject to collective bargaining agreements. Four of these agreements, covering approximately 15% of the Company's employees, have expired or will expire in 2005.

8. INCOME TAXES

The Company's current and deferred components of income tax expense are as follows:

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
	(IN MILLIONS)		
Current			
Federal	$ 56	$ 30	$ 86
State	9	4	10
Total current	65	34	96
Deferred			
Federal	12	11	(3)
State	11	14	(6)
Total deferred	23	25	(9)
Income tax expense	$ 88	$ 59	$ 87

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
	(IN MILLIONS)		
Income before income taxes	$ 208	$ 188	$ 231
Federal statutory rate	35%	35%	35%
Income tax expense at statutory rate	73	66	81
Increase (decrease) in tax resulting from:			
Capital loss benefit	(72)	--	--
State income taxes, net of valuation allowances and federal income tax benefit	13	12	2
Valuation allowance, capital loss	72	--	--
Changes in estimates for prior year items	--	(19)	--
Deferred tax asset write-off	--	--	4
Other, net	2	--	--
Total	15	(7)	6
Income tax expense	$ 88	$ 59	$ 87
Effective Rate	42.2%	31.3%	37.5%

Following are the Company's tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases:

	DECEMBER 31, 2003	DECEMBER 31, 2004
	(IN MILLIONS)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	9	13
Total current deferred tax assets	9	13
Non-current:		
Employee benefits	63	81
Operating and capital loss carryforwards	81	30
Deferred gas costs	18	68
Other	52	66
Valuation allowance	(73)	(20)
Total non-current deferred tax assets	141	225
Total deferred tax assets	150	238
Deferred tax liabilities:		
Current:		
Non-trading derivative liabilities, net	18	1
Total current deferred tax liabilities	18	1
Non-current:		
Depreciation	746	827
Regulatory liability	27	17
Other	13	22
Total non-current deferred tax liabilities	786	866
Total deferred tax liabilities	804	867
Accumulated deferred income taxes, net	$ 654	$ 629

The Company is included in the consolidated income tax returns of CenterPoint Energy. CenterPoint Energy's consolidated federal income tax returns have been audited and settled through the 1996 tax year. The 1997 through 2003 consolidated federal income tax returns are currently under audit.

Tax Attribute Carryforwards. At December 31, 2004, the Company had $327 million of state net operating loss carryforwards. The losses are available to offset future state taxable income through the year 2023. Substantially all of the state loss carryforwards will expire between 2012 and 2020. A valuation allowance has been established against approximately 33% of the state net operating loss carryforwards.

The valuation allowance reflects a net decrease of $10 million and $53 million in 2003 and 2004, respectively. These net changes resulted from a reassessment of the Company's future ability to use federal and state capital loss carryforwards and state tax net operating loss carryforwards.

Tax Contingencies. As of December 31, 2004, approximately $13 million of federal tax reserve has been reclassified to current tax liability. The Company has also reserved for tax items primarily relating to certain positions taken with respect to state tax filings. The total amount reserved is approximately $10 million.

9. COMMITMENTS AND CONTINGENCIES

(a) COMMITMENTS

Environmental Capital Commitments. The Company has various commitments for capital and environmental expenditures. The Company anticipates no significant capital and other special project expenditures between 2005 and 2009 for environmental compliance.

Fuel Commitments. Fuel commitments include several long-term natural gas contracts related to the Company's natural gas distribution operations, which have various quantity requirements and durations that are not classified as non-trading derivative assets and liabilities in the Company's Consolidated Balance Sheets as of December 31, 2004 as these contracts meet the SFAS No. 133 exception to be classified as "normal purchases contracts" or do not meet the definition of a derivative. Minimum payment obligations for natural gas supply contracts are approximately $807 million in 2005, $401 million in 2006, $193 million in 2007, $29 million in 2008 and $1 million in 2009.

(b) LEASE COMMITMENTS

The following table sets forth information concerning the Company's obligations under non-cancelable long-term operating leases, principally consisting of rental agreements for building space, data processing equipment and vehicles, including major work equipment (in millions):

2005	$ 20
2006	16
2007	12
2008	11
2009	6
2010 and beyond	26
Total	$ 91

Total rental expense for all operating leases was $31 million, $28 million and $30 million in 2002, 2003 and 2004, respectively.

(c) LEGAL MATTERS

Natural Gas Measurement Lawsuits. CERC Corp. and certain of its subsidiaries are defendants in a suit filed in 1997 under the Federal False Claims Act alleging mismeasurement of natural gas produced from federal and Indian lands. The suit seeks undisclosed damages, along with statutory penalties, interest, costs, and fees. The complaint is part of a larger series of complaints filed against 77 natural gas pipelines and their subsidiaries and affiliates. An earlier single action making substantially similar allegations against the pipelines was dismissed by the federal district court for the District of Columbia on grounds of improper joinder and lack of jurisdiction. As a result, the various individual complaints were filed in numerous courts throughout the country. This case has been consolidated, together with the other similar False Claims Act cases, in the federal district court in Cheyenne, Wyoming.

In addition, CERC Corp. and certain of its subsidiaries are defendants in two mismeasurement lawsuits brought against approximately 245 pipeline companies and their affiliates pending in state court in Stevens County, Kansas. In one case (originally filed in May 1999 and amended four times), the plaintiffs purport to represent a class of royalty owners who allege that the defendants have engaged in systematic mismeasurement of the volume of natural gas for more than 25 years. The plaintiffs amended their petition in this suit in July 2003 in response to an order from the judge denying certification of the plaintiffs' alleged class. In the amendment the plaintiffs dismissed their claims against certain defendants (including two of the Company's subsidiaries), limited the scope of the class of plaintiffs they purport to represent and eliminated previously asserted claims based on mismeasurement of the Btu content of the gas. The same plaintiffs then filed a second lawsuit, again as representatives of a class of royalty owners, in which they assert their claims that the defendants have engaged in systematic mismeasurement of the Btu content of natural gas for more than 25 years. In both lawsuits, the plaintiffs seek compensatory damages, along with statutory penalties, treble damages, interest, costs and fees. The Company believes that there has been no systematic mismeasurement of gas and that the suits are without merit. The Company does not expect that the ultimate outcome will have a material impact on its financial condition or results of operations.

Gas Cost Recovery Litigation. In October 2002, a suit was filed in state district court in Wharton County, Texas against the Company, CenterPoint Energy, Entex Gas Marketing Company, and certain non-affiliated companies alleging fraud, violations of the Texas Deceptive Trade Practices Act, violations of the Texas Utilities Code, civil conspiracy and violations of the Texas Free Enterprise and Antitrust Act with respect to rates charged to certain consumers of natural gas in the State of Texas. Subsequently the plaintiffs added as defendants CenterPoint Energy Marketing Inc., CenterPoint Energy Gas Transmission Company, United Gas, Inc., Louisiana Unit Gas Transmission Company, CenterPoint Energy Pipeline Services, Inc., and CenterPoint Energy Trading and Transportation Group, Inc. The plaintiffs allege that defendants inflated the prices charged to certain consumers of natural gas. In February 2003, a similar suit was filed in state court in Caddo Parish, Louisiana against the Company with respect to rates charged to a purported class of certain consumers of natural gas and gas service in the State of Louisiana. In February 2004, another suit was filed in state court in Calcasieu Parish, Louisiana against the Company seeking to recover alleged overcharges for gas or gas services allegedly provided by Southern Gas

Operations to a purported class of certain consumers of natural gas and gas service without advance approval by the LPSC. In October 2004, a similar case was filed in district court in Miller County, Arkansas against the Company, CenterPoint Energy, Entex Gas Marketing Company, CenterPoint Energy Gas Transmission Company, CenterPoint Energy Field Services, CenterPoint Energy Pipeline Services, Inc., Mississippi River Transmission Corp. and other non-affiliated companies alleging fraud, unjust enrichment and civil conspiracy with respect to rates charged to certain consumers of natural gas in at least the states of Arkansas, Louisiana, Mississippi, Oklahoma and Texas. At the time of the filing of each of the Caddo and Calcasieu Parish cases, the plaintiffs in those cases filed petitions with the LPSC relating to the same alleged rate overcharges. The Caddo and Calcasieu Parish cases have been stayed pending the resolution of the respective proceedings by the LPSC. The plaintiffs in the Miller County case seek class certification, but the proposed class has not been certified. In November 2004, the Miller case was removed to federal district court in Texarkana, Arkansas. In February 2005, the Wharton County case was removed to federal district court in Houston, Texas, and in March 2005, the plaintiffs in the Wharton County case moved to dismiss the case and agreed not to refile the claims asserted unless the Miller County case is not certified as a class action or is later decertified. The range of relief sought by the plaintiffs in these cases includes injunctive and declaratory relief, restitution for the alleged overcharges, exemplary damages or trebling of actual damages, civil penalties and attorney's fees. In these cases, the Company, CenterPoint Energy and their affiliates deny that they have overcharged any of their customers for natural gas and believe that the amounts recovered for purchased gas have been in accordance with what is permitted by state regulatory authorities. The Company and CenterPoint Energy do not anticipate that the outcome of these matters will have a material impact on the financial condition or results of operations of either the Company or CenterPoint Energy.

(d) ENVIRONMENTAL MATTERS

Hydrocarbon Contamination. CERC Corp. and certain of its subsidiaries are among the defendants in lawsuits filed beginning in August 2001 in Caddo Parish and Bossier Parish, Louisiana. The suits allege that, at some unspecified date prior to 1985, the defendants allowed or caused hydrocarbon or chemical contamination of the Wilcox Aquifer, which lies beneath property owned or leased by certain of the defendants and which is the sole or primary drinking water aquifer in the area. The primary source of the contamination is alleged by the plaintiffs to be a gas processing facility in Haughton, Bossier Parish, Louisiana known as the "Sligo Facility," which was formerly operated by a predecessor in interest of CERC Corp. This facility was purportedly used for gathering natural gas from surrounding wells, separating gasoline and hydrocarbons from the natural gas for marketing, and transmission of natural gas for distribution.

Beginning about 1985, the predecessors of certain CERC Corp. defendants engaged in a voluntary remediation of any subsurface contamination of the groundwater below the property they owned or leased. This work has been done in conjunction with and under the direction of the Louisiana Department of Environmental Quality. The plaintiffs seek monetary damages for alleged damage to the aquifer underlying their property, unspecified alleged personal injuries, alleged fear of cancer, alleged property damage or diminution of value of their property, and, in addition, seek damages for trespass, punitive, and exemplary damages. The Company believes the ultimate cost associated with resolving this matter will not have a material impact on the financial condition or results of operations of the Company.

Manufactured Gas Plant Sites. The Company and its predecessors operated manufactured gas plants (MGP) in the past. In Minnesota, the Company has completed remediation on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in the Company's Minnesota service territory. The Company believes that it has no liability with respect to two of these sites.

At December 31, 2004, the Company had accrued $18 million for remediation of certain Minnesota sites. At December 31, 2004, the estimated range of possible remediation costs for these sites was $7 million to $42 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. The Company has utilized an environmental expense tracker mechanism in its rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2004, the Company has collected or accrued $13 million from insurance companies and ratepayers to be used for future environmental remediation.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by the Company or may have been owned by one of its former affiliates. The Company has been named as a defendant in lawsuits under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of the Company or its divisions. The Company has also been identified as a PRP by the State of Maine for a site that is the subject of one of the lawsuits. The Company is investigating details regarding these sites and the range of environmental expenditures for potential remediation. However, the Company believes it is not liable as a former owner or operator of those sites under the Comprehensive Environmental, Response, Compensation and Liability Act of 1980, as amended, and applicable state statutes, and is vigorously contesting those suits and its designation as a PRP.

Mercury Contamination. The Company's pipeline and distribution operations have in the past employed elemental mercury in measuring and regulating equipment. It is possible that small amounts of mercury may have been spilled in the course of normal maintenance and replacement operations and that these spills may have contaminated the immediate area with elemental mercury. This type of contamination has been found by the Company at some sites in the past, and the Company has conducted remediation at these sites. It is possible that other contaminated sites may exist and that remediation costs may be incurred for these sites. Although the total amount of these costs cannot be known at this time, based on experience by the Company and that of others in the natural gas industry to date and on the current regulations regarding remediation of these sites, the Company believes that the costs of any remediation of these sites will not be material to the Company's financial condition, results of operations or cash flows.

Other Environmental. From time to time the Company has received notices from regulatory authorities or others regarding its status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, the Company has been named from time to time as a defendant in litigation related to such sites. Although the ultimate outcome of such matters cannot be predicted at this time, the Company does not believe, based on its experience to date, that these matters, either individually or in the aggregate, will have a material adverse effect on the Company's financial condition, results of operations or cash flows.

OTHER PROCEEDINGS

In 2005, the Company received a communication from a regulatory agency indicating that the agency had ordered a predecessor company to remove certain components from a portion of its distribution system prior to the date the Company acquired it. Those components are not in compliance with current state and federal codes, and it is possible that some of those components remain in the Company's system. The Company has not completed its analysis of the cost to locate and replace such components; however, the Company believes that the disposition of this matter will not have a material adverse effect on the Company's financial condition, results of operations or cash flows.

The Company is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Company's management regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Company's management believes that the disposition of these matters will not have a material adverse effect on the Company's financial condition, results of operations or cash flows.

10. ESTIMATED FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair values of cash and cash equivalents, investments in debt and equity securities classified as "available-for-sale" and "trading" in accordance with SFAS No. 115, and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair values of non-trading derivative assets and liabilities are equivalent to their carrying amounts in the Consolidated Balance Sheets at December 31, 2003 and 2004 and have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques (see Note 5). Therefore, these financial instruments are stated at fair value and are excluded from the table below.

	DECEMBER 31, 2003		DECEMBER 31, 2004	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Financial liabilities:				
Long-term debt (excluding capital leases)...	$ 2,371	$ 2,612	$ 2,368	$ 2,659

11. UNAUDITED QUARTERLY INFORMATION

Summarized quarterly financial data is as follows:

	YEAR ENDED DECEMBER 31, 2003			
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN MILLIONS)			
Revenues	$ 2,094	$ 1,032	$ 950	$ 1,574
Operating income	172	67	33	87
Net income (loss)	88	15	(10)	36

	YEAR ENDED DECEMBER 31, 2004			
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN MILLIONS)			
Revenues	$ 2,196	$ 1,323	$ 1,219	$ 2,245
Operating income	160	64	32	137
Net income (loss)	74	11	(2)	61

12. REPORTABLE BUSINESS SEGMENTS

Because the Company is an indirect wholly owned subsidiary of CenterPoint Energy, the Company's determination of reportable business segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting policies except that some executive benefit costs have not been allocated to business segments.

The Company's reportable business segments include the following: Natural Gas Distribution, Pipelines and Gathering and Other Operations. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers and non-rate regulated retail gas marketing operations for commercial and industrial customers. Pipelines and Gathering includes the interstate natural gas pipeline operations and the natural gas gathering and pipeline services businesses. Other Operations consists primarily of other corporate operations which support all of the Company's business operations.

Long-lived assets include net property, plant and equipment, net goodwill and other intangibles and equity investments in unconsolidated subsidiaries. The Company accounts for intersegment sales as if the sales were to third parties, that is, at current market prices.

Financial data for business segments and products and services are as follows:

	NATURAL GAS DISTRIBUTION	PIPELINES AND GATHERING	OTHER OPERATIONS	RECONCILING ELIMINATIONS	CONSOLIDATED
			(IN MILLIONS)		
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2002:					
Revenues from external customers and affiliates	3,953 (1)	255 (2)	--	--	4,208
Intersegment revenues	7	119	--	(126)	--
Depreciation and amortization	126	41	--	--	167
Operating income	198	153	2	--	353
Total assets	4,428	2,500	206	(685)	6,449
Expenditures for long-lived assets	196	70	--	--	266
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2003:					
Revenues from external customers and affiliates	5,406 (1)	244 (2)	--	--	5,650
Intersegment revenues	29	163	9	(201)	--
Depreciation and amortization	136	40	--	--	176
Operating income (loss)	202	158	(1)	--	359
Total assets	4,661	2,519	388	(715)	6,853
Expenditures for long-lived assets	199	66	--	--	265
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2004:					
Revenues from external customers and affiliates	6,681 (1)	306 (2)	(4)	--	6,983
Intersegment revenues	3	145	5	(153)	--
Depreciation and amortization	143	44	--	--	187
Operating income (loss)	222	180	(9)	--	393
Total assets	4,798	2,637	792	(694)	7,533
Expenditures for long-lived assets	197	73	(1)	--	269

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(1) Included in the Natural Gas Distribution revenues from external customers and affiliates are sales to RRI, a former affiliate, of $9 million for the year ended December 31, 2002, and sales to Texas Genco, of $26 million, $28 million and $20 million for the years ended December 31, 2002, 2003 and 2004, respectively.

(2) Included in the Pipelines and Gathering revenues from external customers and affiliates are sales to RRI, a former affiliate, of $33 million for the year ended December 31, 2002, and sales to Texas Genco of $2 million, $3 million and $2 million for the years ended December 31, 2002, 2003 and 2004, respectively.

	YEAR ENDED DECEMBER 31, 2002	2003	2004
		(IN MILLIONS)	
REVENUES BY PRODUCTS AND SERVICES:			
Retail gas sales	$ 3,857	$ 5,310	$ 6,583
Gas transportation	255	244	306
Energy products and services	96	96	94
Total	$ 4,208	$ 5,650	$ 6,983

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholder of
CenterPoint Energy Resources Corp.
Houston, Texas

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp. and subsidiaries (the Company) as of December 31, 2004 and 2003, and the related consolidated statements of income, comprehensive income, cash flows and stockholder's equity for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of CenterPoint Energy Resources Corp. and subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP

Houston, Texas
March 23, 2005

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

DISCLOSURE CONTROLS AND PROCEDURES

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2004 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information called for by Item 10 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 11. EXECUTIVE COMPENSATION

The information called for by Item 11 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information called for by Item 12 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information called for by Item 13 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees billed to the Company during the fiscal years ending December 31, 2003 and 2004 by its principal accounting firm, Deloitte & Touche LLP, are set forth below. These fees do not include certain fees related to general corporate matters, financial reporting, tax and other fees which have not been allocated to the Company by CenterPoint Energy.

	YEAR ENDED DECEMBER 31,	
	2003	2004
Audit fees	$ 864,259	$ 840,408
Audit-related fees	53,935	79,075
Total audit and audit-related fees	918,194	919,483
Tax fees	--	--
All other fees	--	--
Total fees	$ 918,194	$ 919,483

The Company is not required to have, and does not have, an audit committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements.

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2004.

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements:

I, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 56.

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

SCHEDULE II -- QUALIFYING VALUATION ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2004

COLUMN A	COLUMN B	COLUMN C ADDITIONS		COLUMN D	COLUMN E
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO INCOME	CHARGED TO OTHER ACCOUNTS(1)	DEDUCTIONS FROM RESERVES(2)	BALANCE AT END OF PERIOD
		(IN THOUSANDS)			
Year Ended December 31, 2004:					
Accumulated provisions:					
Uncollectible accounts receivable.......	$ 27,975	$ 26,017	$ --	$ 26,059	$ 27,933
Deferred tax asset valuation allowance..	73,248	(67,428)	14,114	--	19,934
Year Ended December 31, 2003:					
Accumulated provisions:					
Uncollectible accounts receivable.......	19,568	23,713	--	15,306	27,975
Deferred tax asset valuation allowance..	82,880	(9,632)	--	--	73,248
Year Ended December 31, 2002:					
Accumulated provisions:					
Uncollectible accounts receivable.......	33,047	15,391	--	28,870	19,568
Deferred tax asset valuation allowance..	14,999	67,881	--	--	82,880

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(1) Charges to other accounts represent changes in presentation to reflect state tax attributes net of federal tax benefit as well as to reflect amounts that were netted against related attribute balances in prior years.

(2) Deductions from reserves represent losses or expenses for which the respective reserves were created. In the case of the uncollectible accounts reserve, such deductions are net of recoveries of amounts previously written off.

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, in the City of Houston, the State of Texas, on the 24th day of March, 2005.

CENTERPOINT ENERGY RESOURCES CORP.
(Registrant)

By: /s/ DAVID M. MCCLANAHAN

David M. McClanahan
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 24, 2005.

SIGNATURE	TITLE
/s/ DAVID M. MCCLANAHAN (David M. McClanahan)	President, Chief Executive Officer and Director (Principal Executive Officer and Director)
/s/ GARY L. WHITLOCK (Gary L. Whitlock)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JAMES S. BRIAN (James S. Brian)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)

CENTERPOINT ENERGY RESOURCES CORP.

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
FOR FISCAL YEAR ENDED DECEMBER 31, 2004

INDEX OF EXHIBITS

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

EXHIBIT NUMBER	DESCRIPTION	REPORT OR REGISTRATION STATEMENT	SEC FILE OR REGISTRATION NUMBER	EXHIBIT REFERENCE
2(a)(1)	-- Agreement and Plan of Merger among the Company, HL&P, HI Merger, Inc. and NorAm dated August 11, 1996	HI's Form 8-K dated August 11, 1996	1-7629	2
2(a)(2)	-- Amendment to Agreement and Plan of Merger among the Company, HL&P, HI Merger, Inc. and NorAm dated August 11, 1996	Registration Statement on Form S-4	333-11329	2(c)
2(b)	-- Agreement and Plan of Merger dated December 29, 2000 merging Reliant Resources Merger Sub, Inc. with and into Reliant Energy Services, Inc.	Registration Statement on Form S-3	333-54526	2
3(a)(1)	-- Certificate of Incorporation of RERC Corp.	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(1)
3(a)(2)	-- Certificate of Merger merging former NorAm Energy Corp. with and into HI Merger, Inc. dated August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(2)
3(a)(3)	-- Certificate of Amendment changing the name to Reliant Energy Resources Corp.	Form 10-K for the year ended December 31, 1998	1-3187	3(a)(3)
3(a)(4)	-- Certificate of Amendment changing the name to CenterPoint Energy Resources Corp.	Form 10-Q for the quarter ended June 30, 2003	1-13265	3(a)(4)
3(b)	-- Bylaws of RERC Corp.	Form 10-K for the year ended December 31, 1997	1-3187	3(b)
4(a)(1)	-- Indenture, dated as of December 1, 1986, between NorAm and Citibank, N.A., as Trustee	NorAm's Form 10-K for the year ended December 31, 1986	1-13265	4.14
4(a)(2)	-- First Supplemental Indenture to Exhibit 4(a)(1) dated as of September 30, 1988	Form 10-K for the year ended December 31, 1997	1-3187	4(a)(2)
4(a)(3)	-- Second Supplemental Indenture to Exhibit 4(a)(1) dated as of November 15, 1989	Form 10-K for the year ended December 31, 1997	1-3187	4(a)(3)
4(a)(4)	-- Third Supplemental Indenture to Exhibit 4(a)(1) dated as of August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	4(a)(4)
4(b)(1)	-- Indenture, dated as of March 31, 1987, between NorAm and Chase Manhattan Bank, N.A., as Trustee, authorizing 6% Convertible Subordinated Debentures due 2012	NorAm's Registration Statement on Form S-3	33-14586	4.20
4(b)(2)	-- Supplemental Indenture to Exhibit 4(b)(1) dated as of August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	4(b)(2)
4(c)(1)	-- Form of Indenture between NorAm and The Bank of New York as Trustee	NorAm's Registration Statement on Form S-3	33-64001	4.8

EXHIBIT NUMBER	DESCRIPTION	REPORT OR REGISTRATION STATEMENT	SEC FILE OR REGISTRATION NUMBER	EXHIBIT REFERENCE
4(c)(2)	-- Form of First Supplemental Indenture to Exhibit 4(c)(1)	NorAm's Form 8-K dated June 10, 1996	1-13265	4.01
4(c)(3)	-- Second Supplemental Indenture to Exhibit 4(c)(1) dated as of August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	4(d)(3)
4(d)	-- Indenture, dated as of December 1, 1997, between RERC Corp. and Chase Bank of Texas, National Association	Registration Statement on Form S-3	333-41017	4.1
4(e)(1)	-- Indenture, dated as of February 1, 1998, between RERC Corp. and Chase Bank of Texas, National Association, as Trustee	Form 8-K dated February 5, 1998	1-13265	4.1
4(e)(2)	-- Supplemental Indenture No. 1, dated as of February 1, 1998, providing for the issuance of RERC Corp.'s 6 1/2% Debentures due February 1, 2008	Form 8-K dated February 5, 1998	1-13265	4.2
4(e)(3)	-- Supplemental Indenture No. 2, dated as of November 1, 1998, providing for the issuance of RERC Corp.'s 6 3/8% Term Enhanced ReMarketable Securities	Form 8-K dated November 9, 1998	1-13265	4.1
4(e)(4)	-- Supplemental Indenture No. 3, dated as of July 1, 2000, providing for the issuance of RERC Corp.'s 8.125% Notes due 2005	Registration Statement on Form S-4	333-49162	4.2
4(e)(5)	-- Supplemental Indenture No. 4, dated as of February 15, 2001, providing for the issuance of RERC Corp.'s 7.75% Notes due 2011	Form 8-K dated February 21, 2001	1-13265	4.1
4(e)(6)	-- Supplemental Indenture No. 5, dated as of March 25, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated March 18, 2003	1-13265	4.1
4(e)(7)	-- Supplemental Indenture No. 6, dated as of April 14, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated April 7, 2003	1-13265	4.2
4(e)(8)	-- Supplemental Indenture No. 7, dated as of November 3, 2003, providing for the issuance of CERC Corp.'s 5.95% Senior Notes due 2014	Form 8-K dated October 29, 2003	1-13265	4.2
4(f)	-- $250,000,000 Credit Agreement, dated as of March 23, 2004, among CERC Corp., as borrower, and the Initial Lenders named therein, as Initial Lenders	Form 8-K dated March 31, 2004	1-13265	4.1

There have not been filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities do not exceed 10% of the total assets of CERC. CERC hereby agrees to furnish a copy of any such instrument to the SEC upon request.

EXHIBIT NUMBER	DESCRIPTION	REPORT OR REGISTRATION STATEMENT	SEC FILE OR REGISTRATION NUMBER	EXHIBIT REFERENCE
10(a)	-- Service Agreement by and between Mississippi River Transmission Corporation and Laclede Gas Company dated August 22, 1989	NorAm's Form 10-K for the year ended December 31, 1989	1-13265	10.20
+12	-- Computation of Ratios of Earnings to Fixed Charges			
+23	-- Consent of Deloitte & Touche LLP			
+31.1	-- Rule 13a-14(a)/15d-14(a) Certification of David M. McClanahan			
+31.2	-- Rule 13a-14(a)/15d-14(a) Certification of Gary L. Whitlock			
+32.1	-- Section 1350 Certification of David M. McClanahan			
+32.2	-- Section 1350 Certification of Gary L. Whitlock			

EXHIBIT 12

CENTERPOINT ENERGY RESOURCES CORP.
(AN INDIRECT WHOLLY OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(THOUSANDS OF DOLLARS)

	YEAR ENDED DECEMBER 31,				
	2000	2001	2002	2003	2004
Income from continuing operations	$ 98,228	$ 67,244	$ 120,060	$ 128,878	$ 144,109
Income taxes for continuing operations	93,272	58,287	87,643	58,706	86,497
Minority interest expense (income)	(37)	(36)	11	(55)	(65)
Capitalized interest	(1,982)	(185)	(1,202)	(851)	(1,791)
	189,481	125,310	206,512	186,678	228,750
Fixed charges, as defined:					
Interest expense	142,861	154,965	153,688	178,973	178,185
Capitalized interest	1,982	185	1,202	851	1,791
Distribution on trust preferred securities	29	28	25	12	--
Interest component of rentals charged to operating expense	10,934	10,369	10,188	9,252	9,978
Total fixed charges	155,806	165,547	165,103	189,088	189,954
Earnings, as defined	$ 345,287	$ 290,857	$ 371,615	$ 375,766	$ 418,704
Ratio of earnings to fixed charges	2.22	1.76	2.25	1.99	2.20

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-54256 on Form S-3 of our reports dated March 23, 2005, relating to the financial statements and financial statement schedules of CenterPoint Energy Resources Corp. appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2004.

DELOITTE & TOUCHE LLP

Houston, Texas
March 23, 2005

EXHIBIT 31.1

CERTIFICATIONS

I, David M. McClanahan, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Resources Corp.;

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

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

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

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

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

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

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

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

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

Date: March 24, 2005

/s/ David M. McClanahan

David M. McClanahan
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATIONS

I, Gary L. Whitlock, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Resources Corp.;

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

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

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

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

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

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

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

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

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

Date: March 24, 2005

/s/ Gary L. Whitlock

Gary L. Whitlock
Executive Vice President and
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the "Company") on Form 10-K for the year ended December 31, 2004 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, David M. McClanahan, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ David M. McClanahan

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David M. McClanahan
President and Chief Executive Officer
March 24, 2005

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the "Company") on Form 10-K for the year ended December 31, 2004 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Gary L. Whitlock, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ Gary L. Whitlock
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Gary L. Whitlock
Executive Vice President and Chief Financial Officer
March 24, 2005