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, 2003

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	76-0511406
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
1111 LOUISIANA HOUSTON, TEXAS 77002	(713) 207-1111
(Address and zip code of principal executive offices)	(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, 2003: None

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We meet the conditions specified in General Instruction I(1)(a) and (b) to 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 Party 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 material changes in the amount of revenue and expense items between 2001, 2002 and 2003.

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 8 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 own two interstate natural gas pipelines and gathering systems and provide various ancillary services. 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 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 affiliate transactions.

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

References to "we," "us," and "our" mean CenterPoint Energy Resources Corp. (CERC Corp.) together with its subsidiaries.

NATURAL GAS DISTRIBUTION

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: CenterPoint Energy Arkla (Arkla), CenterPoint Energy Entex (Entex) and CenterPoint Energy Minnegasco (Minnegasco). These operations are regulated as natural gas utility operations in the jurisdictions served by these divisions. Our operations also include non-rate regulated retail gas sales to and transportation services for commercial and industrial customers in the six states listed above as well as several other Midwestern states.

- Arkla provides natural gas distribution services to approximately 695,000 customers in over 245 communities in Arkansas, Louisiana, Oklahoma and Texas. The largest metropolitan areas served by Arkla are Little Rock, Arkansas and Shreveport, Louisiana. In 2003, approximately 70% of Arkla's total throughput was attributable to retail sales of natural gas and approximately 30% was attributable to transportation services.

- Entex provides natural gas distribution services to approximately 1.6 million customers in over 500 communities in Louisiana, Mississippi and Texas. The largest metropolitan area served by Entex is Houston. In 2003, approximately 94% of Entex's total throughput was attributable to retail sales of natural gas and approximately 6% was attributable to transportation services.

- Minnegasco provides natural gas distribution services to approximately 746,000 customers in over 240 communities in Minnesota. The largest metropolitan area served by Minnegasco is Minneapolis. In 2003, approximately 94% of Minnegasco's total throughput was attributable to retail sales of natural gas and approximately 6% was attributable to transportation services. Additionally, Minnegasco provides unregulated services consisting of heating, ventilating and air conditioning (HVAC) equipment and appliance sales and repair services, and home security monitoring.

The demand for natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers is seasonal. In 2003, approximately 74% of the total throughput of our natural gas distribution 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

Arkla. In 2003, Arkla purchased virtually all of its natural gas supply pursuant to term contracts, with terms varying from a few months to three years. Arkla's major third party suppliers in 2003 included BP America Production Company (29%), Oneok Energy Marketing and Trading LLC (23%), CenterPoint Energy Gas Services, Inc. (CEGS) (13%) and Conoco Phillips Company (9%). Numerous other suppliers provided the remaining 26% of Arkla's natural gas supply requirements. Arkla transports substantially all of its natural gas supplies under contracts with our pipeline subsidiaries.

Entex. In 2003, Entex purchased virtually all of its natural gas supply pursuant to term contracts, with terms varying from one to five years. Entex's major third party suppliers in 2003 included American Electric Power Company, Inc. (43%), Kinder Morgan, Inc. (20%), CEGS (11%), and Entergy-Koch, LP (11%). Numerous other suppliers provided the remaining 15% of Entex's natural gas supply requirements. Entex transports its natural gas supplies through various interstate and intrastate pipelines under long-term contracts with terms varying from one to five years.

Minnegasco. In 2003, Minnegasco purchased approximately 77% of its natural gas supply pursuant to term contracts, with terms varying from a few months to two years. Minnegasco purchased the remaining 23% of its natural gas supply on the spot market. Minnegasco's major third party suppliers in 2003 included BP Canada Energy Marketing (53%), Duke Energy Trading & Marketing (8%), Tenaska Marketing Ventures (6%), Mirant Americas Energy Marketing (5%) and NG Energy Trading (5%). Minnegasco transports its natural gas supplies through various interstate pipelines under long-term contracts with terms varying from one to five years.

Generally, the regulations of the states in which our natural gas distribution business operates allow it to pass through changes in the costs of natural gas to its customers under purchased gas adjustment provisions in its tariffs. There is, however, a timing difference between our purchases of natural gas and the ultimate recovery of these costs. Consequently, we may incur carrying costs as a result of this timing difference that are not recoverable from our customers.

Arkla and Minnegasco 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. Minnegasco also supplements contracted supplies and storage from time to time with stored liquefied natural gas and propane-air plant production.

Minnegasco 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). Minnegasco 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). Minnegasco owns a liquefied natural gas facility 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 firm customer requirements; however, it is possible for limited service disruptions 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.

Commercial and Industrial Sales

Our commercial and industrial sales business, conducted through CEGS and CenterPoint Energy Intrastate Gas Pipeline, provides comprehensive natural gas products and services to commercial and industrial customers in the Gulf Coast and Midwestern regions of the United States. Most services provided by CEGS are not subject to rate regulation. In 2003, the commercial and industrial sales business represented over 50% of the throughput of our Natural Gas Distribution business segment. During that period, approximately 94% of the commercial and industrial group's total throughput was attributable to natural gas sales; the remainder was attributable to transportation services provided to third parties and affiliates. For more information on CEGS's derivative instruments and hedging activities, please read "Quantitative and Qualitative Disclosures About Market Risk -- Commodity Price Risk From Non-Trading Activities" in Item 7A of this report and Note 5 to our consolidated financial statements.

Assets

As of December 31, 2003, we owned approximately 63,000 linear miles of gas distribution lines, 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 pipeline services.

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.

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 2003, approximately 25% of our total operating revenues from pipelines and gathering was attributable to services provided to Arkla, and approximately 10% 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 Arkla and Laclede are provided under several long-term firm storage and transportation agreements. Contracts for firm transportation in Arkla's major service areas are currently scheduled to expire in 2005. The Arkansas Public Service Commission (APSC) is currently reviewing Arkla's request to enter into a seven-year contract for firm transportation with CEGT. The agreement to provide services to Laclede expires in 2007.

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 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 its 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.

OTHER OPERATIONS

In 2003, 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 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, 2003, 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, 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%.

FEDERAL ENERGY REGULATORY COMMISSION

The transportation and sale or resale of natural gas in interstate commerce is subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act and the Natural Gas Policy Act of 1978, as amended. The FERC has jurisdiction over, 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. 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 are further required to post their Implementation Procedures on their websites by June 1, 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 August 2002, a settlement was approved by the APSC that resulted in an increase in the base rate and service charge revenues of Arkla of approximately $27 million annually. In addition, the APSC approved a gas main replacement surcharge that provided $2 million of additional revenue in 2003 and is expected to provide additional amounts in subsequent years. In December 2002, a settlement was approved by the Oklahoma Corporation Commission that resulted in an increase in the base rate and service charge revenues of Arkla of approximately $6 million annually. In November 2003, Arkla filed a request with the Louisiana Public Service Commission (LPSC) for a $16 million increase to its base rate and service charge revenues in Louisiana. The case is expected to be resolved in mid-2004.

In December 2003, a settlement was approved by the City of Houston that will result in an increase in the base rate and service charge revenues of Entex of approximately $7 million annually. Entex has submitted these settlement rates to the 28 other cities within its Houston Division and the Railroad Commission for consideration and approval. If all regulatory approvals are received from these 29 jurisdictions, Entex's base rate and service charge revenues are expected to increase by approximately $7 million annually in addition to the $7 million increase discussed above. On February 10, 2004, a settlement was approved by the LPSC that is expected to result in an increase in Entex's base rate and service charge revenues of approximately $2 million annually.

Our gas distribution divisions generally recover the cost of gas provided to customers through gas cost adjustment mechanisms prescribed in their tariffs that are approved by the appropriate regulatory authority. Recently, our Arkla and Entex divisions have been involved in both litigation and regulatory proceedings in which parties have challenged the gas costs that have been recovered from customers. In response to a claim by the City of Tyler, Texas that excessive costs, ranging from $2.8 million to $39.2 million, may have been incurred for gas purchased by Entex for resale to residential and small commercial customers, Entex and the City of Tyler have requested that the Railroad Commission determine whether Entex has properly and lawfully charged and collected for gas service to its residential and commercial customers in its Tyler distribution system for the period beginning November 1, 1992, and ending October 31, 2002. Similarly, a complaint has been filed with the LPSC by a private party alleging that certain gas costs recovered from Entex customers in Louisiana were excessive and/or were not properly authorized by the LPSC. Additionally, certain private litigants have filed suit in Louisiana state courts, alleging that inappropriate or excessive gas costs have been recovered from Arkla's customers.

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. These regulations provided guidance on, among other things, the areas that should be classified as HCA.

Our Pipelines and Gathering business segment 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

We are subject to a number of federal, state and local laws and regulations relating to the protection of the environment and the safety and health of company personnel and the public. These requirements relate to a broad range of our activities, including:

- the discharge of pollutants into the air, water and soil;

- the identification, generation, storage, handling, transportation, disposal, record keeping, labeling and reporting of, and the emergency response in connection with, hazardous and toxic materials and wastes, associated with our operations;

- noise emissions from our facilities; and

- safety and health standards, practices and procedures that apply to the workplace and the operation of our facilities.

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;

- 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.

If we do not comply with environmental requirements that apply to our operations, regulatory agencies could seek to impose on us civil, administrative and/or criminal liabilities as well as seek to curtail our operations. Under some statutes, private parties could also seek to impose upon us civil fines or liabilities for property damage, personal injury and possibly other costs.

Under the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), owners and operators of facilities from which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances, are liable for:

- the costs of responding to that release or threatened release; and

- the restoration of natural resources damaged by any such release.

LIABILITY FOR PREEXISTING CONDITIONS AND REMEDIATION

Hydrocarbon Contamination. We and certain of our subsidiaries are among some of 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 ours. 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 quantity of monetary damages sought is unspecified. We are unable to estimate the monetary damages, if any, that the plaintiffs may be awarded in these matters.

Manufactured Gas Plant Sites. We and our predecessors operated manufactured gas plants (MGP) in the past. In Minnesota, remediation has been completed on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in our Minnesota service territory, two of which we believe were neither owned nor operated by us, and for which we believe we have no liability.

At December 31, 2003, we had accrued $19 million for remediation of certain Minnesota sites. At December 31, 2003, the estimated range of possible remediation costs for these sites was $8 million to $44 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. We have collected or accrued $12.5 million as of December 31, 2003 to be used for environmental remediation.

We have received notices from the United States Environmental Protection Agency and others regarding our status as a PRP for other sites. We have been named as a defendant in lawsuits under which contribution is sought for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of ours or our divisions. We are investigating details regarding these sites and the range of environmental expenditures for potential remediation. Based on current information, we have not been able to quantify a range of environmental expenditures for such sites.

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. This type of contamination has been found by us 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, 2003, we had 5,464 full-time employees. The following table sets forth the number of our employees by business segment as of December 31, 2003:

BUSINESS SEGMENT	NUMBER	NUMBER REPRESENTED BY UNIONS OR OTHER COLLECTIVE BARGAINING GROUPS
Natural Gas Distribution................	4,813	1,549
Pipelines and Gathering.................	651	-
Total.................................	5,464	1,549

As of December 31, 2003, approximately 28% of our employees are subject to collective bargaining agreements. Two of these agreements, covering approximately 9% of our employees, have expired or will expire in 2004.

The Minnegasco division of our natural gas distribution business has 512 bargaining unit employees that are covered by collective bargaining unit agreements that have expired or will expire in 2004. An agreement with the International Brotherhood of Electrical Workers Local 949, which expired in December 2003, was renegotiated in February 2004 covering 267 of these employees. The remaining 245 employees are covered by a collective bargaining agreement with the Office and Professional Employees International Union Local 12, which expires in May 2004.

RISK FACTORS

PRINCIPAL RISK FACTORS ASSOCIATED WITH OUR BUSINESSES

RATE REGULATION OF OUR BUSINESS MAY DELAY OR DENY FULL RECOVERY OF OUR COSTS.

Our rates for natural gas distribution 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 is, generally, premised on providing a reasonable opportunity to recover reasonable and necessary operating expenses and to earn a reasonable return on invested capital, there can be no assurance that the municipalities and state commissions will judge all of our costs to be reasonable or necessary or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs.

OUR BUSINESSES MUST COMPETE WITH ALTERNATIVE ENERGY SOURCES, AND OUR PIPELINES AND GATHERING BUSINESSES MUST COMPETE DIRECTLY WITH OTHERS IN THE TRANSPORTATION AND STORAGE 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 marketed, sold or transported by us 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 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 our service territory. Additionally, increasing gas prices could create the need for us to provide collateral in order to purchase gas.

WE MAY INCUR CARRYING COSTS ASSOCIATED WITH PASSING THROUGH CHANGES IN THE COSTS OF NATURAL GAS.

Generally, the regulations of the states in which we operate allow us to pass through changes in the costs of natural gas to our customers through purchased gas adjustment provisions in the applicable tariffs. There is, however, a timing difference between our purchases of natural gas and the ultimate recovery of these costs. Consequently, we may incur carrying costs as a result of this timing difference that are not recoverable from our customers. The failure to recover those additional carrying costs may have an adverse effect on our results of operations, financial condition and cash flows.

IF WE FAIL TO EXTEND CONTRACTS WITH TWO OF OUR SIGNIFICANT PIPELINE CUSTOMERS, THERE COULD BE AN ADVERSE IMPACT ON OUR OPERATIONS.

Contracts with two of our significant pipeline customers, Arkla and Laclede, are currently scheduled to expire in 2005 and 2007, respectively. To the extent the pipelines are unable to extend these contracts or the contracts are renegotiated at rates substantially different than the rates provided in the current contracts, there could be an adverse effect on our results of operations, financial condition and cash flows.

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

Our interstate pipelines 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 FINANCIAL CONDITION

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

As of December 31, 2003, we had $2.4 billion of outstanding indebtedness. Approximately $518 million principal amount of this debt must be paid through 2006. In addition, the capital constraints and other factors currently impacting our parent company's and our businesses may require our future indebtedness to include terms that are more restrictive or burdensome than those of our current or historical indebtedness. These terms may negatively impact our ability to operate our business or adversely affect our financial condition and results of operations. 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. CenterPoint Energy and its subsidiaries other than us have approximately $3.0 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 ratings could be adversely affected.

WE ARE A 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.

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 certain of 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 affiliate transactions.

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. CenterPoint Energy must seek a new order before the expiration date. 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.

The United States Congress is currently considering legislation that has a provision 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. Also, most 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 COMMON STOCK AND RELATED STOCKHOLDER MATTERS

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

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 2002 and 2003, we paid dividends on our common stock of $350 million and $-0-, respectively, to CenterPoint Energy, Inc.

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 THE 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.

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 (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). For information about the 1935 Act, please read " -- Liquidity -- Certain Contractual and Regulatory Limits on Ability to Issue Securities and Pay Dividends."

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.

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 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; 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, 2001, 2002 and 2003, 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.

SELECTED FINANCIAL RESULTS

	YEAR ENDED DECEMBER 31,		
	2001	2002	2003
	(IN MILLIONS)		
Revenues	$ 5,044	$ 4,208	$ 5,650
Expenses:			
Natural gas	3,781	2,901	4,297
Operation and maintenance	657	667	688
Depreciation and amortization	207	167	176
Taxes other than income taxes	133	120	130
Total	4,778	3,855	5,291
Operating Income	266	353	359
Interest Expense and Distribution on Trust Preferred Securities	(155)	(153)	(179)
Other Income, net	14	8	8
Income Before Income Taxes	125	208	188
Income Tax Expense	(58)	(88)	(59)
Net Income	$ 67	$ 120	$ 129

2003 Compared to 2002. Our operating income increased $6 million in 2003 compared to 2002 due to higher revenues from rate increases implemented late in 2002 ($33 million), increased margins due to higher commodity prices ($8 million), improved margins from new transportation contracts to power plants ($7 million), improved margins from our unregulated commercial and industrial sales ($6 million), continued customer growth ($6 million) and improved margins from enhanced services in our gas gathering operations ($4 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), higher pension, employee benefit and other miscellaneous expenses ($27 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). Project work expenses included in operation and maintenance expense decreased and were offset by a corresponding decrease in revenues billed for these services ($14 million). 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 relating to our Minnesota operations.

2002 Compared to 2001. Our operating income increased $87 million in 2002 compared to 2001 primarily as a result of improved margins from rate increases in 2002, a 5% increase in throughput and changes in estimates of unbilled revenues and deferred gas costs, which reduced operating margins in 2001 ($37 million). Depreciation and amortization decreased primarily as a result of the discontinuance of goodwill amortization in 2002 in accordance with Statement of Financial Accounting Standards (SFAS) SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) as further discussed in Note 2(d) to our consolidated financial statements ($49 million). Our effective tax rate for 2002 and 2001 was 42.2% and 46.4%, respectively. The decrease in the effective rate for 2002 compared to 2001 was primarily the result of the discontinuance of goodwill amortization in accordance with SFAS No. 142, offset by an increase in state income taxes.

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

Capital Requirements. We anticipate investing up to an aggregate $1.5 billion in capital expenditures in the years 2004 through 2008, including approximately $308 million and $349 million in 2004 and 2005, respectively.

The following table sets forth estimates of our contractual obligations to make future payments for 2004 through 2008 and thereafter (in millions):

CONTRACTUAL OBLIGATIONS	TOTAL	2004	2005	2006	2007	2008	2009 AND THEREAFTER
Long-term debt.......................	$ 2,371	$ -	$ 367	$ 161	$ 7	$307	$ 1,529
Short-term borrowings, including credit facilities..................	63	63	-	-	-	-	-
Operating leases(1)..................	60	25	10	8	4	3	10
Non-trading derivative liabilities...	10	7	2	1	-	-	-
Other commodity commitments(2).......	2,151	1,045	565	344	171	24	2
Total contractual cash obligations.	$ 4,655	$1,140	$ 944	$ 514	$182	$334	$ 1,541

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

(2) 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. In connection with our November 2002 amendment and extension of our $150 million receivables facility, 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 Sheet. On June 25, 2003, we elected to reduce the receivables facility to $100 million and in January 2004, the $100 million receivables facility was replaced with a $250 million receivables facility terminating in January 2005. For additional information regarding this transaction please read Note 2(i) to our consolidated financial statements.

Long-Term and Short-Term Debt. In 2003, we completed several capital market and bank financing transactions which, collectively, increased our borrowing capacity, converted a portion of our interest payment obligations from floating rates to fixed rates and refinanced current maturities of long-term debt. The proceeds of the debt transactions in 2003 were primarily used to refinance existing short-term debt with long-term debt, refinance maturing debt and pay related debt issuance costs. Our 2003 capital market transactions included the following:

ISSUANCE DATE	BORROWER	SECURITY	PRINCIPAL AMOUNT (IN MILLIONS)	INTEREST RATE	MATURITY DATE
March and April 2003	CERC Corp.	Senior Notes	$ 762	7.875%	April 2013
November 2003	CERC Corp.	Senior Notes	160	5.950%	January 2014

In 2003, we also entered into a new credit facility, which increased liquidity and extended the termination date of the facility it replaced. As of December 31, 2003, we had the following credit facility.

DATE EXECUTED	COMPANY	SIZE OF FACILITY AT DECEMBER 31, 2003 (IN MILLIONS)	AMOUNT OUTSTANDING AT DECEMBER 31, 2003 (IN MILLIONS)	TERMINATION DATE	TYPE OF FACILITY
March 25, 2003	CERC Corp.	$ 200	$ 63	March 23, 2004	Revolver

We are currently in discussions with banks seeking to arrange a replacement revolving credit facility and expect to have such a facility in place on or prior to the termination date of the existing facility. In the first quarter of 2004, we replaced our $100 million receivables facility with a $250 million committed one-year receivables facility. The bankruptcy remote subsidiary established in 2002 continues to buy our receivables and sell them to an unrelated third party.

At December 31, 2003, we had a shelf registration statement covering $50 million of debt securities.

Cash Requirements in 2004. 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 2004 include the following:

- approximately $308 million of capital expenditures; and

- maturity of any borrowings under our $200 million revolving credit agreement.

We expect that revolving credit borrowings, anticipated cash flows from operations and borrowings from affiliates will be sufficient to meet our cash needs for 2004.

Impact on Liquidity of a Downgrade in Credit Ratings. As of March 1, 2004, 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	OUTLOOK(1)	RATING	OUTLOOK(2)	RATING	OUTLOOK(3)
Ba1	Negative	BBB	Negative	BBB	Negative

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(1) A "negative" outlook from Moody's reflects concerns over the next 12 to 18 months which will either lead to a review for a potential downgrade or a return to a stable outlook.

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

(3) A "negative" 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 $200 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 that could exist in connection with certain contracts relating to gas purchases, gas price hedging and gas storage activities of our Natural Gas Distribution business segment.

Our revolving credit facility contains a "material adverse change" clause that could impact our ability to make new borrowings under this facility. The "material adverse change" clause in our revolving credit facility relates to any material adverse change in the business, condition, operations, performance or properties of the borrower or the borrower and its subsidiaries taken as a whole.

CenterPoint Energy Gas Services, Inc. (CEGS), a wholly owned subsidiary of CERC Corp., provides comprehensive natural gas sales and services to industrial and commercial customers, which 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, 2003, the senior unsecured debt of CERC Corp. was rated BBB by S&P and Ba1 by Moody's. We estimate that as of December 31, 2003, unsecured credit limits extended to CEGS by counterparties could aggregate $62 million; however, utilized credit capacity is significantly lower.

Cross Defaults. Our debentures and borrowings generally provide that a default on obligations by CenterPoint Energy does not cause a default under our debentures, revolving credit facility or receivables facility. A payment default on, or a non-payment default that permits acceleration of, any indebtedness at CERC Corp. exceeding $50 million will cause a default under CenterPoint Energy's $2.3 billion credit facility entered into in October 2003. 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 on senior debt of CenterPoint Energy aggregating $1.4 billion.

Pension Plan. As discussed in Note 7 to the consolidated financial statements, we participate in CenterPoint Energy's qualified non-contributory pension plan covering substantially all employees. Pension expense for 2004 is estimated to be $31 million based on an expected return on plan assets of 9.0% and a discount rate of 6.25% as of December 31, 2003. Pension expense for the year ended December 31, 2003 was $36 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.

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; and

- various regulatory actions.

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. Our money pool borrowing limit under such financing orders is $600 million. At December 31, 2003, we had no investments in the money pool or borrowings from the money pool. The money pool may not provide sufficient funds to meet our cash needs.

Certain Contractual and Regulatory Limits on Ability to Issue Securities and Pay Dividends. Factors affecting our ability to issue securities, pay dividends on our common stock or take other actions to adjust our capitalization include:

- covenants and other provisions in our credit facility and receivables facility; and

- limitations imposed on us under the 1935 Act.

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 bank facility also contains a provision that could, under certain circumstances, limit the amount of dividends that could be paid by us. We are in compliance with such covenants.

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 affiliate transactions.

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 March 1, 2004, we are authorized to issue an additional $2 million of debt and an additional aggregate $250 million of preferred stock and preferred securities after giving effect to our capital market transactions in 2003.

The SEC has reserved jurisdiction over, and must take further action to permit, the issuance of $480 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 at least thirty percent (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. Unforeseen events and changes in circumstances and market condition 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 for a discussion of new accounting pronouncements.

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, mandatorily redeemable preferred securities of subsidiary trusts 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 $347 million and $63 million at December 31, 2002 and 2003, respectively. If the floating interest rates were to increase by 10% from their levels at December 31, 2003, our combined interest expense would increase by a total of $0.03 million each month in which such increase continued.

At December 31, 2002 and 2003, we had outstanding fixed-rate debt and trust preferred securities aggregating $2.0 billion and $2.4 billion, respectively, in principal amount and having a fair value of $2.1 billion and $2.6 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 $74 million if interest rates were to decline by 10% from their levels at December 31, 2003. 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 compressor fuel or other 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, 2002 levels would have decreased the fair value of our Non-Trading Energy Derivatives by $12 million. 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.

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 CenterPoint Energy's trading, marketing, risk management services and hedging activities. The committee's duties are to establish CenterPoint Energy's 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.

CenterPoint Energy'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.

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, 2001	2002	2003
		(IN THOUSANDS)	
REVENUES	$ 5,044,419	$ 4,207,836	$ 5,649,720
EXPENSES:			
Natural gas	3,781,200	2,900,682	4,296,928
Operation and maintenance	657,515	666,502	688,281
Depreciation and amortization	207,203	167,456	175,975
Taxes other than income taxes	132,560	119,911	129,846
Total	4,778,478	3,854,551	5,291,030
OPERATING INCOME	265,941	353,285	358,690
OTHER INCOME (EXPENSE):			
Interest expense and distribution on trust preferred securities	(154,993)	(153,713)	(178,985)
Other, net	14,583	8,131	7,879
Total	(140,410)	(145,582)	(171,106)
INCOME BEFORE INCOME TAXES	125,531	207,703	187,584
Income Tax Expense	58,287	87,643	58,706
NET INCOME	$ 67,244	$ 120,060	$ 128,878

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,		
	2001	2002	2003
	(IN THOUSANDS)		
Net income	$ 67,244	$ 120,060	$ 128,878
Other comprehensive income (loss), net of tax:			
Minimum non-qualified pension liability adjustment (net of tax of $4,703 and $790)	8,279	1,468	-
Cumulative effect of adoption of SFAS No. 133 (net of tax of $20,511)	38,092	-	-
Net deferred gain (loss) from cash flow hedges (net of tax of $23,821, $35,142 and $15,405)	(11,826)	46,062	21,971
Reclassification of net deferred loss (gain) from cash flow hedges realized in net income (net of tax of $18,947, $5,681 and $569)	(61,449)	381	1,297
Other comprehensive income (loss)	(26,904)	47,911	23,268
Comprehensive income	$ 40,340	$ 167,971	$ 152,146

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, 2002	DECEMBER 31, 2003
	(IN THOUSANDS)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,237	$ 34,447
Accounts receivable, principally customers, net	380,317	462,988
Accrued unbilled revenue	284,112	323,844
Inventory	135,707	187,226
Non-trading derivative assets	27,275	45,897
Taxes receivable	61,512	32,023
Prepaid expenses	20,767	11,104
Deferred tax asset	10,186	--
Other	29,998	71,597
Total current assets	959,111	1,169,126
PROPERTY, PLANT AND EQUIPMENT, NET	3,630,470	3,735,561
OTHER ASSETS:		
Goodwill, net	1,740,510	1,740,510
Other intangibles, net	19,878	20,101
Non-trading derivative assets	3,866	11,273
Notes receivable -- affiliated companies, net	39,097	33,929
Other	55,570	142,162
Total other assets	1,858,921	1,947,975
TOTAL ASSETS	$ 6,448,502	$ 6,852,662
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Short-term borrowings	$ 347,000	$ 63,000
Current portion of long-term debt	517,616	--
Accounts payable, principally trade	465,694	528,394
Accounts and notes payable -- affiliated companies, net	101,231	23,351
Taxes accrued	57,057	65,636
Interest accrued	49,084	58,505
Customer deposits	54,081	58,372
Non-trading derivative liabilities	9,973	6,537
Accumulated deferred income taxes, net	--	8,856
Other	102,510	125,132
Total current liabilities	1,704,246	937,783
OTHER LIABILITIES:		
Accumulated deferred income taxes, net	606,075	645,125
Non-trading derivative liabilities	873	3,330
Benefit obligations	132,434	130,980
Other	520,673	571,005
Total other liabilities	1,260,055	1,350,440
LONG-TERM DEBT	1,441,264	2,370,974
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
CERC OBLIGATED MANDATORILY REDEEMABLE CONVERTIBLE PREFERRED SECURITIES OF SUBSIDIARY TRUST HOLDING SOLELY JUNIOR SUBORDINATED DEBENTURES OF CERC	508	--
STOCKHOLDER'S EQUITY	2,042,429	2,193,465
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$ 6,448,502	$ 6,852,662

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,		
	2001	2002	2003
	(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 67,244	$ 120,060	$ 128,878
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	207,203	167,456	175,975
Deferred income taxes	30,320	23,003	25,097
Amortization of deferred financing costs	1,096	2,770	8,424
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	677,383	3,275	(121,864)
Accounts receivable/payable, affiliates	17,497	(65,688)	(3,784)
Inventory	(22,048)	8,762	(51,519)
Taxes receivable	--	(61,512)	29,489
Accounts payable	(436,875)	198,045	61,589
Fuel cost recovery	8,292	28,317	(11,350)
Interest and taxes accrued	(7,114)	7,653	18,000
Net non-trading derivative assets and liabilities	6,775	13,527	17,828
Other current assets	(29,573)	(32,833)	(31,936)
Other current liabilities	15,256	11,604	26,913
Other assets	(21,571)	100,118	19,663
Other liabilities	(4,726)	(92,064)	40,250
Other, net	(7,067)	1,370	(14,481)
Net cash provided by operating activities	502,092	433,863	317,172
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(263,257)	(266,208)	(265,061)
Other, net	(4,834)	9,726	(7,581)
Net cash used in investing activities	(268,091)	(256,482)	(272,642)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments of long-term debt	(155,569)	(6,653)	(507,795)
Proceeds from long-term debt	585,632	--	928,525
Increase (decrease) in short-term borrowings, net	(289,473)	1,473	(284,000)
Increase (decrease) in notes with affiliates, net	(216,758)	170,658	(68,928)
Dividends to parent	(400,000)	(350,000)	--
Capital contribution from parent	241,352	--	--
Debt issuance costs	--	--	(87,122)
Other, net	(5,336)	(47)	--
Net cash used in financing activities	(240,152)	(184,569)	(19,320)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(6,151)	(7,188)	25,210
CASH AND CASH EQUIVALENTS AT BEGINNING OF THE YEAR	22,576	16,425	9,237
CASH AND CASH EQUIVALENTS AT END OF THE YEAR	$ 16,425	$ 9,237	$ 34,447
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash Payments:			
Interest	$ 148,303	$ 146,244	$ 164,040
Income taxes (refunds)	49,872	125,085	(49,033)

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

	COMMON STOCK SHARES	COMMON STOCK AMOUNT	PAID IN CAPITAL	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TOTAL STOCKHOLDER'S EQUITY
				(IN THOUSANDS)		
Balance at December 31, 2000	1,000	$ 1	$ 2,410,716	$ --	$ (9,747)	$ 2,400,970
Net income	--	--	--	67,244	--	67,244
Dividend to parent	--	--	(334,593)	(65,407)	--	(400,000)
Transfer of benefits to parent	--	--	(62,080)	--	--	(62,080)
Contributions from parent	--	--	241,352	--	--	241,352
Other comprehensive income (loss), net of tax:						
Cumulative effect of adoption of SFAS No 133	--	--	--	--	38,092	38,092
Net deferred loss from cash flow hedges	--	--	--	--	(11,826)	(11,826)
Reclassification of net deferred gain from cash flow hedges realized in net income	--	--	--	--	(61,449)	(61,449)
Additional minimum non-qualified pension liability adjustment	--	--	--	--	8,279	8,279
Balance at December 31, 2001	1,000	1	2,255,395	1,837	(36,651)	2,220,582
Net income	--	--	--	120,060	--	120,060
Dividend to parent	--	--	(272,907)	(77,093)	--	(350,000)
Contributions from parent	--	--	3,876	--	--	3,876
Other comprehensive income, net of tax:						
Net deferred gain from cash flow hedges	--	--	--	--	46,062	46,062
Reclassification of net deferred loss from cash flow hedges realized in net income	--	--	--	--	381	381
Minimum non-qualified pension liability adjustment	--	--	--	--	1,468	1,468
Balance at December 31, 2002	1,000	1	1,986,364	44,804	11,260	2,042,429
Net income	--	--	--	128,878	--	128,878
Other	--	--	(1,110)	--	--	(1,110)
Other comprehensive income, net of tax:						
Net deferred gain from cash flow hedges	--	--	--	--	21,971	21,971
Reclassification of net deferred loss from cash flow hedges realized in net income	--	--	--	--	1,297	1,297
Balance at December 31, 2003	1,000	$ 1	$ 1,985,254	$ 173,682	$ 34,528	$ 2,193,465

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.), formerly named Reliant Energy Resources Corp. (RERC Corp.), together with its subsidiaries (collectively, the Company), distributes natural gas, transports natural gas through its interstate pipelines and provides natural gas gathering and pipeline services. CERC Corp. is a Delaware corporation.

The Company's natural gas distribution operations (Natural Gas Distribution) are conducted by three unincorporated divisions: CenterPoint Energy Entex (Entex), CenterPoint Energy Minnegasco (Minnegasco) and CenterPoint Energy Arkla (Arkla) and other non-rate regulated retail gas marketing operations. The Company's pipelines and gathering operations (Pipelines and Gathering) are primarily conducted by two wholly owned pipeline subsidiaries, CenterPoint Energy Gas Transmission Company (CEGT) and CenterPoint Energy-Mississippi River Transmission Corporation (MRT), and a wholly owned gas gathering subsidiary, CenterPoint Energy Field Services, Inc. (CEFS). The Company's principal operations are located in Arkansas, Louisiana, Minnesota, Mississippi, Missouri, Oklahoma and Texas.

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 (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 affiliate transactions.

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 to 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 2003 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.

Other investments, excluding marketable securities, are generally carried at cost.

(c) REVENUES

The Company records natural gas sales and services under the accrual method and these revenues are generally recognized upon delivery. Natural gas sales and services not billed by month-end are accrued based upon estimated purchased gas volumes, estimated lost and unaccounted for gas and currently effective tariff rates. Pipelines and Gathering 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 all repair and maintenance costs as incurred. The cost of utility plant and equipment retirements is charged to accumulated depreciation. Property, plant and equipment includes the following:

	ESTIMATED USEFUL LIVES (YEARS)	DECEMBER 31, 2002	DECEMBER 31, 2003
		(IN MILLIONS)	
Natural gas distribution................	5-50	$ 2,151	$ 2,316
Pipelines and gathering.................	5-75	1,686	1,722
Other property..........................	3-20	49	49
Total.................................		3,886	4,087
Accumulated depreciation................		(256)	(351)
Property, plant and equipment, net....		$ 3,630	$ 3,736

For further information regarding removal costs previously recorded as a component of accumulated depreciation, see Note 2(n).

In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which provides that goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and written down and charged to results of operations only in the periods in which the recorded value of goodwill and certain intangibles with indefinite lives is more than its fair value. On January 1, 2002, the Company adopted the provisions of the statement which apply to goodwill and intangible assets acquired prior to June 30, 2001.

With the adoption of SFAS No. 142, the Company ceased amortization of goodwill as of January 1, 2002. A reconciliation of previously reported net income to the amounts adjusted for the exclusion of goodwill amortization follows:

	YEAR ENDED DECEMBER 31, 2001	2002	2003
		(IN MILLIONS)	
Reported net income.......................	$ 67	$ 120	$ 129
Add: Goodwill amortization, net of tax....	49	--	--
Adjusted net income.......................	$ 116	$ 120	$ 129

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

	DECEMBER 31, 2002 CARRYING AMOUNT	DECEMBER 31, 2002 ACCUMULATED AMORTIZATION	DECEMBER 31, 2003 CARRYING AMOUNT	DECEMBER 31, 2003 ACCUMULATED AMORTIZATION
		(IN MILLIONS)		
Land Use Rights....	$ 7	$ (2)	$ 7	$ (3)
Other..............	18	(3)	20	(4)
Total..............	$ 25	$ (5)	$ 27	$ (7)

The Company recognizes specifically identifiable intangibles when specific rights and contracts are acquired.

The Company has no intangible assets with indefinite lives recorded as of December 31, 2003. 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 2001, 2002, and 2003 was $0.8 million, $1.1 million and $1.5 million, respectively. Estimated amortization expense is approximately $3 million in 2004 and $1 million per year for the four succeeding fiscal years.

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

	DECEMBER 31, 2002 AND 2003
Natural Gas Distribution...	$ 1,085
Pipelines and Gathering....	601
Other Operations...........	55
Total....................	$ 1,741

The Company completed its review of goodwill impairment during the second quarter of 2003 for its reporting units pursuant to SFAS No. 142. No impairment was indicated as a result of this assessment.

(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 Natural Gas Distribution and MRT. As of December 31, 2002 and 2003, the Company had recorded $31 million and $34 million of regulatory assets, respectively, which are included in other long-term assets on our Consolidated Balance Sheets. As of December 31, 2002 and 2003, the Company had recorded $19 million and $434 million of regulatory liabilities, respectively, which are included in other long-term liabilities on our Consolidated Balance Sheets. Included in regulatory liabilities at December 31, 2003, is $415 million of removal costs that resulted from a reclassification of removal costs from accumulated depreciation in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). For further information, see Note 2(n).

If events were to occur that would make 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. In addition, the Company would be required to determine any impairment of the carrying costs of plant and inventory assets.

(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, goodwill amortization and other amortization expense for 2001, 2002 and 2003.

	YEAR ENDED DECEMBER 31,		
	2001	2002	2003
	(IN MILLIONS)		
Depreciation expense....................	$ 146	$ 153	$ 161
Goodwill amortization expense...........	49	--	--
Other amortization expense..............	12	14	15
Total depreciation and amortization...	$ 207	$ 167	$ 176

(g) CAPITALIZATION OF INTEREST

Interest and allowance for funds used during construction (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 2001, 2002 and 2003, the Company capitalized interest and AFUDC of $0.2 million, $1.2 million and $0.9 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. 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, principally customers, net, are net of an allowance for doubtful accounts of $20 million and $28 million at December 31, 2002 and 2003, respectively. The provisions for doubtful accounts in the Company's Statements of Consolidated Income for 2001, 2002 and 2003 were $46 million, $15 million and $24 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," and, as a result, the related receivables are excluded from the Consolidated Balance Sheets. Effective June 25, 2003, the Company elected to reduce the purchase limit under the receivables facility from $150 million to $100 million. As of December 31, 2002 and 2003, the Company had utilized $107 million and $100 million of its receivables facility, respectively.

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.

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.

(j) INVENTORY

Inventory consists principally of materials and supplies and natural gas and is primarily valued at the lower of average cost or market. Inventory includes the following components:

	DECEMBER 31,	
	2002	2003
	(IN MILLIONS)	
Materials and supplies...	$ 32	$ 27
Natural gas..............	104	160
Total inventory........	$ 136	$ 187

(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 in the Company's Consolidated Balance Sheets and any unrealized gain or loss, net of tax, as a separate component of stockholder's 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, 2002 and 2003, the Company held no "available-for-sale" 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. Subject to SFAS No. 71, a corresponding regulatory asset is recorded in anticipation of recovery through the rate making process by subsidiaries that apply SFAS No. 71.

(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

Effective January 1, 2003, the Company adopted SFAS No. 143. SFAS No. 143 requires the fair value of an asset retirement obligation to be recognized as a liability is incurred and capitalized as part of the cost of the related tangible long-lived assets. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2002 and 2003, these removal costs of $395 million and $415 million, respectively, have been reclassified from accumulated depreciation to other long-term liabilities in the Consolidated Balance Sheets.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 149 clarifies when a contract with an initial net investment meets the characteristics of a derivative as discussed in SFAS No. 133 and when a derivative contains a financing component. SFAS No. 149 also amends certain existing pronouncements, which will result in more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003, and should be applied prospectively. Certain paragraphs of this statement that relate to forward purchases or sales of when-issued securities or other securities that do not yet exist should be applied to both existing contracts and new contracts entered into after June 30, 2003. The provisions of this statement that relate to SFAS No. 133 implementation issues that have been effective for fiscal quarters that began prior to June 15, 2003 should continue to be applied in accordance with their respective effective dates. The adoption of SFAS No. 149 did not have a material effect on the Company's consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (SFAS No. 150). SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. Effective July 1, 2003, upon the adoption of SFAS No. 150, the Company reclassified $0.4 million of trust preferred securities as long-term debt and began to recognize the dividends paid on the trust preferred securities as interest expense. Prior to July 1, 2003, the dividends were classified as "Distribution on Trust Preferred Securities" in the Statements of Consolidated Income. SFAS No. 150 does not permit restatement of prior periods. The adoption of SFAS No. 150 did not impact the Company's net income. See discussion of FIN 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51" (FIN 46) below regarding the accounting for the trust preferred securities at December 31, 2003.

In January 2003, the FASB issued 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. FIN 46 is effective for all new variable interest entities created or acquired after January 31, 2003, subject to the following additional releases by the FASB. On October 9, 2003, the FASB deferred the application for FIN 46 until the end of the first interim period or annual period ending after December 15, 2003 if the variable interest was created before February 1, 2003 and a public entity had not issued financial statements reporting the variable interest entity in accordance with FIN 46. On December 24, 2003, the FASB issued a revision to FIN 46 (FIN 46-R). The effective dates and impact of FIN 46 and FIN 46R are as follows: (a) for special-purpose entities (SPE's) created before February 1, 2003, the Company must apply the provisions of FIN 46 or FIN 46-R at the end of the first interim or annual reporting period ending after December 15, 2003, (b) for variable interest entities created before February 1, 2003 which do not meet the definition of an SPE provided by FIN 46-R, the Company is required to adopt FIN 46-R at the end of the first interim or annual period ending after March 15, 2004 and (c) for all entities, regardless of whether an SPE, that were created subsequent to December 31, 2003, the Company is required to apply the provisions of FIN 46-R immediately. The Company has subsidiary trusts that have Mandatorily Redeemable Preferred Securities outstanding with a liquidation value of $0.4 million as of December 31, 2003. These securities were issued in 1996 and were previously reported on the Company's Consolidated Balance Sheet as CERC Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of CERC (see disclosure above on SFAS No. 150). The trusts were determined to be SPE's, and therefore, the provisions of FIN 46 or FIN 46-R were applicable to the trusts for the December 31, 2003 financial statements. The trusts were determined to be variable interest entities under FIN 46-R. The Company also determined that it is not the primary beneficiary of the trusts. Therefore, the trusts and the mandatorily redeemable preferred securities issued by the trusts are no longer reported on the Company's Consolidated Balance Sheet as of December 31, 2003. Instead, the Company reports its junior subordinated debentures due to the trusts as long-term debt. See Note 6. The Company has made this reclassification as of December 31, 2003 and has elected not to restate prior period information. The Company is currently evaluating the impact of adopting FIN 46-R applicable to non-SPE's created prior to February 1, 2003 but does not expect a material impact.

On December 23, 2003, the FASB issued SFAS No. 132 (Revised 2003), "Employer's Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132(R)) which increases the existing disclosure requirements by requiring more details about pension plan assets, benefit obligations, cash flows, benefit costs and related information. Companies will be required to segregate plan assets by category, such as debt, equity and real estate, and to provide certain expected rates of return and other informational disclosures. SFAS No. 132(R) also requires companies to disclose various elements of pension and postretirement benefit costs in interim-period financial statements for quarters beginning after December 15, 2003. The Company has adopted the disclosure requirements of SFAS No. 132(R) in Note 7 to these consolidated financial statements.

In December 2003, Congress passed the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) which will become effective in 2006. The Act contains incentives for the Company, if it continues to provide prescription drug benefits for its retirees, through the provision of a non-taxable reimbursement to the Company of specified costs. The Company has many different alternatives available under the Act, and, until clarifying regulations are issued with respect to the Act, the Company is unable to determine the financial impact. On January 12, 2004, the FASB issued FASB Staff Position (FSP) FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FAS 106-1). In accordance with FSP FAS 106-1, the Company's postretirement benefits obligations and net periodic postretirement benefit cost in the financial statements and accompanying notes do not reflect the effects of the legislation. Specific authoritative guidance on the accounting for the legislation is pending and that guidance, when issued, may require the Company to change previously reported information.

3. REGULATORY MATTERS

(a) RATE CASES

In August 2002, a settlement was approved by the Arkansas Public Service Commission (APSC) that resulted in an increase in the base rate and service charge revenues of Arkla of approximately $27 million annually. In addition, the APSC approved a gas main replacement surcharge that provided $2 million of additional revenue in 2003 and is expected to provide additional amounts in subsequent years.

In December 2002, a settlement was approved by the Oklahoma Corporation Commission that resulted in an increase in the base rate and service charge revenues of Arkla of approximately $6 million annually.

In November 2003, Arkla filed a request with the Louisiana Public Service Commission (LPSC) for a $16 million increase to its base rate and service charge revenues in Louisiana. The case is expected to be resolved in mid-2004.

In December 2003, a settlement was approved by the City of Houston that will result in an increase in the base rate and service charge revenues of Entex of approximately $7 million annually. Entex has submitted these settlement rates to the 28 other cities within its Houston Division and the Railroad Commission of Texas for consideration and approval. If all regulatory approvals are received from these 29 jurisdictions, Entex's base rate and service charge revenues are expected to increase by approximately $7 million annually in addition to the $7 million increase discussed above.

On February 10, 2004, a settlement was approved by the LPSC that is expected to result in an increase in Entex's base rate and service charge revenues of approximately $2 million annually.

(b) OTHER REGULATORY PROCEEDINGS

City of Tyler, Texas Dispute. In July 2002, the City of Tyler, Texas, asserted that Entex had overcharged residential and small commercial customers in that city for excessive gas costs under supply agreements in effect since 1992. That dispute has been referred to the Texas Railroad Commission by agreement of the parties for a determination of whether Entex has properly and lawfully charged and collected for gas service to its residential and commercial customers in its Tyler distribution system for the period beginning November 1, 1992, and ending October 31, 2002. The Company believes that all costs for Entex's Tyler distribution system have been properly included and recovered from customers pursuant to Entex's filed tariffs.

FERC Contract Inquiry. On September 15, 2003, the Federal Energy Regulatory Commission (FERC) issued a Show Cause Order to CEGT, one of the Company's natural gas pipeline subsidiaries. In its Show Cause Order, the FERC contended that CEGT failed to file with the FERC and post on the internet certain information relating to negotiated rate contracts that CEGT had entered into pursuant to 1996 FERC orders. Those orders authorized CEGT to enter into negotiated rate contracts that deviate from the rates prescribed under CEGT's filed FERC tariffs. The FERC also alleged that certain of the contracts contain provisions that CEGT was not authorized to negotiate under the terms of the 1996 orders.

Following issuance of the Show Cause Order, CEGT made certain compliance filings, met with members of the FERC's staff and provided additional information relating to the FERC's Show Cause Order. On March 4, 2004, the FERC issued orders accepting CEGT's compliance filings and approving a Stipulation and Consent Agreement with CEGT that resolved the issues raised by the Show Cause Order. The resolution of these issues did not have a material impact on our results of operations, financial condition and cash flows.

4. RELATED PARTY TRANSACTIONS

From time to time, the Company has receivables from, or payables to, CenterPoint Energy or its subsidiaries.

	DECEMBER 31, 2002	DECEMBER 31, 2003
	(IN MILLIONS)	
Accounts receivable from affiliates	$ 21	$ 6
Accounts payable to affiliates	(48)	(29)
Accounts receivable/(payable) -- affiliated companies, net	(27)	(23)
Note receivable from affiliates	29	--
Notes payable to affiliates	(103)	--
Notes receivable/(payable) -- affiliated companies, net	(74)	--
Account and notes payable -- affiliated companies, net	$ (101)	$ (23)
Long-term notes receivable from affiliates	$ 75	$ 67
Long-term notes payable from affiliates	(36)	(33)
Long-term notes receivable -- affiliated companies, net	$ 39	$ 34

For the years ended December 31, 2001, 2002 and 2003, the Company had net interest income (expense) related to affiliate borrowings of $5 million, ($2) million and $3 million, respectively.

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

In 2002, the Company supplied natural gas to Reliant Energy Services, Inc. (Reliant Energy Services), a subsidiary of Reliant Resources, Inc. (Reliant Resources), which was an affiliate through September 30, 2002. During 2001 and 2002, the sales and services by the Company to Reliant Resources and its subsidiaries totaled $181 million and $42 million, respectively. During 2002 and 2003, the sales and services by the Company to CenterPoint Energy and its affiliates totaled $28 million and $32 million, respectively. Purchases of natural gas by the Company from Reliant Resources and its subsidiaries were $639 million and $204 million in 2001 and 2002, respectively.

CenterPoint Energy provides some corporate services to the Company. The costs of services have been directly charged 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 $77 million, $107 million and $113 million for 2001, 2002 and 2003, respectively, and are included primarily in operation and maintenance expenses.

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 to mitigate the impact of changes and cash flows of 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 2003, no hedge ineffectiveness was recognized in earnings from derivatives that are designated and qualify as Cash Flow Hedges. 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 income. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive income 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, 2003, the Company expects $39 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 three years. The Company's policy is not to exceed five years in hedging its exposure.

(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, 2002 and 2003:

	DECEMBER 31, 2002		DECEMBER 31, 2003	
	INVESTMENT GRADE(1)(2)	TOTAL	INVESTMENT GRADE(1)(2)	TOTAL (3)
Energy marketers	$ 7	$ 22	$ 24	$ 35
Financial institutions	9	9	21	21
Other	--	--	--	1
Total	$ 16	$ 31	$ 45	$ 57

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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 encompasses 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 $35 million non-trading derivative asset includes an $11 million asset due to trades with Reliant Energy Services, a former affiliate. As of December 31, 2003, Reliant Energy Services did not have an investment grade rating.

(c) GENERAL POLICY.

CenterPoint Energy has established a Risk Oversight Committee comprised of corporate and business segment officers that oversees commodity price and credit risk activities, including the trading, marketing, risk management services and hedging activities of CenterPoint Energy and its subsidiaries, including us. The committee's duties are to establish 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 CenterPoint Energy's risk management policies and procedures and trading limits established by CenterPoint Energy's board of directors.

CenterPoint Energy'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, 2002		DECEMBER 31, 2003	
	LONG-TERM	CURRENT(1)	LONG-TERM	CURRENT(1)
	(IN MILLIONS)			
Short-term borrowings:				
Bank loans		$ 347		$ --
Revolving credit facility		--		63
Total short-term borrowings		347		63
Long-term debt:				
Convertible subordinated debentures 6.00% due 2012	$ 76	--	$ 74	--
Senior notes 5.95% to 8.90% due 2005 to 2014	1,331	500	2,251	--
Junior subordinated debentures payable to affiliate 6.25% due 2026(2)	--	--	6	--
Other	36	5	36	--
Unamortized discount and premium(3)	(2)	13	4	--
Total long-term debt	1,441	518	2,371	--
Total borrowings	$ 1,441	$ 865	$ 2,371	$ 63

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

(2) The junior subordinated debentures were issued to subsidiary trusts in connection with the issuance by those trusts 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 trusts 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 $7 million and $6 million at December 31, 2002 and 2003, respectively, which is being amortized over the remaining term of the related long-term debt.

(a) SHORT-TERM BORROWINGS

Credit Facilities. At December 31, 2003, CERC Corp. had a revolving credit facility that provided for an aggregate of $200 million in committed credit. At December 31, 2003, $63 million was borrowed under this revolving credit facility. This revolver terminates on March 23, 2004. Rates for borrowings under this facility, including the facility fee, are London interbank offered rate (LIBOR) plus 250 basis points based on current credit ratings and the applicable pricing grid. The revolving credit facility contains various business and financial covenants. CERC Corp. is prohibited from making loans to or other investments in CenterPoint Energy. CERC Corp. is currently in compliance with the covenants under the credit agreement. CERC Corp. is currently in discussions with banks seeking to arrange a replacement revolving credit facility and expects to have such a facility in place on or prior to the termination date of the existing facility.

The weighted average interest rate on external short-term borrowings as of December 31, 2002 and 2003 was 1.7% and 5.0%, respectively. These interest rates exclude facility fees and other fees paid in connection with the arrangement of the bank facilities.

(b) LONG-TERM DEBT

On March 25 and April 14, 2003, the Company issued $650 million aggregate principal amount and $112 million aggregate principal amount, respectively, of 7.875% senior notes due in 2013. A portion of the proceeds was used to refinance $360 million aggregate principal amount of the Company's 6 3/8% Term Enhanced ReMarketable Securities (TERM Notes) and to pay costs associated with the refinancing. Proceeds were also used to repay approximately $340 million of bank borrowings under the Company's $350 million revolving credit facility prior to its expiration on March 31, 2003.

On November 3, 2003, the Company issued $160 million aggregate principal amount of its 5.95% senior notes due 2014. The Company accepted $140 million aggregate principal amount of its TERM Notes maturing in November 2003 and $1.25 million as consideration for the unsecured senior notes. The Company retired the TERM notes received and used the remaining proceeds to finance remaining costs of issuance of the notes and for general corporate purposes.

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. As discussed in Note 2(n), upon the Company's adoption of FIN 46, the junior subordinated debentures discussed above are included in long-term debt as of December 31, 2003.

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.

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, 2002 and 2003, $0.4 million liquidation amount of convertible preferred securities were outstanding. 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, 2003, 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 $-0- in 2004, $367 million in 2005, $161 million in 2006, $7 million in 2007 and $307 million in 2008. The 2004 amount is net of accumulated sinking fund payments that can be satisfied with bonds that had been acquired and retired as of December 31, 2003.

Transportation Agreement. A subsidiary of CERC Corp. had an agreement (ANR Agreement) with ANR Pipeline Company (ANR) that contemplated that this subsidiary would transfer to ANR an interest in some of CERC Corp.'s pipeline and related assets. In 2001, this subsidiary was transferred to Reliant Resources as a result of CenterPoint Energy's planned divestiture of certain unregulated business operations. However, the Company retained the pipelines covered by the ANR Agreement. Therefore, the subsequent divestiture of Reliant Resources by CenterPoint Energy on September 30, 2002, resulted in a conversion of the Company's obligation to ANR into an obligation to Reliant Resources. As of December 31, 2002, the Company had recorded $5 million and $36 million in current portion of long-term debt and long-term debt, respectively, and as of December 31, 2003, the Company had recorded $-0- and $36 million in current portion of long-term debt and long-term debt, respectively, in its Consolidated Balance Sheets to reflect this obligation for the use of 130 million cubic feet (Mmcf)/day of capacity in some of the Company's transportation facilities. The volume of transportation declined to 100 Mmcf/day in the year 2003 and CERC refunded $5 million to Reliant Resources. The ANR Agreement will terminate in 2005 with a refund of $36 million to Reliant Resources.

(c) RESTRICTIONS ON DEBT

CERC Corp.'s credit facility and receivables facility contain various business and financial covenants requiring CERC Corp. to, among other things, maintain leverage (as defined in the credit facilities), below a specified ratio. These covenants are not anticipated to materially restrict borrowings or the sale of receivables under these facilities. As of December 31, 2003, CERC Corp. was in compliance with these debt covenants.

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 $1 million, $13 million and $36 million for the years ended December 31, 2001, 2002 and 2003, respectively.

In addition to the Plan, the Company participates in CenterPoint Energy's non-qualified pension 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 $5 million, $2 million and $3 million for the years ended December 31, 2001, 2002 and 2003, 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. A substantial portion of the matching contribution is initially invested in CenterPoint Energy common stock. CenterPoint Energy allocates to the Company the savings plan benefit expense related to the Company's employees.

Savings plan benefit expense was $12 million, $17 million and $15 million for the years ended December 31, 2001, 2002 and 2003, 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.

On January 12, 2004, the FASB issued FSP FAS 106-1. In accordance with FSP FAS 106-1, the Company's postretirement benefits obligations and net periodic postretirement benefit cost in the financial statements and accompanying notes do not reflect the effects of the legislation. Specific authoritative guidance on the accounting for the legislation is pending and that guidance, when issued, may require the Company to change previously reported information.

The net postretirement benefit cost includes the following components:

	YEAR ENDED DECEMBER 31,		
	2001	2002	2003
	(IN MILLIONS)		
Service cost -- benefits earned during the period	$ 2	$ 2	$ 2
Interest cost on projected benefit obligation	9	9	10
Expected return on plan assets	(1)	(2)	(2)
Net amortization	2	2	2
Net postretirement benefit cost	$ 12	$ 11	$ 12

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

	YEAR ENDED DECEMBER 31,		
	2001	2002	2003
Discount rate	7.50%	7.25%	6.75%
Expected return on plan assets	10.0%	9.5%	9.0%

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 2002 and 2003.

	YEAR ENDED DECEMBER 31,	
	2002	2003
	(IN MILLIONS)	
CHANGE IN BENEFIT OBLIGATION		
Accumulated benefit obligation, beginning of year	$ 131	$ 155
Service cost	2	2
Interest cost	9	10
Benefits paid	(17)	(18)
Participant contributions	3	4
Plan amendments	--	(2)
Actuarial loss	27	20
Accumulated benefit obligation, end of year	$ 155	$ 171
CHANGE IN PLAN ASSETS		
Plan assets, beginning of year	$ 18	$ 18
Benefits paid	(17)	(18)
Employer contributions	16	14
Participant contributions	3	4
Actual investment return	(2)	3
Plan assets, end of year	$ 18	$ 21
RECONCILIATION OF FUNDED STATUS		
Funded status	$ (137)	$ (150)
Unrecognized prior service cost	19	15
Unrecognized actuarial loss	21	40
Net amount recognized	$ (97)	$ (95)
AMOUNTS RECOGNIZED IN BALANCE SHEETS		
Benefit obligations	$ (97)	$ (95)
Net amount recognized at end of year	$ (97)	$ (95)

	YEAR ENDED DECEMBER 31,	
	2002	2003
ACTUARIAL ASSUMPTIONS		
Discount rate	6.75%	6.25%
Expected long-term on assets	9.0%	8.5%
Healthcare cost trend rate assumed for the next year	11.25%	10.50%
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, 2002	December 31, 2003

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	$ 1	$ 1
Effect on the postretirement benefit obligation	10	9

The following table displays the weighted average asset allocations as of December 31, 2002 and 2003 for the Company's postretirement benefit plan:

	DECEMBER 31,	
	2002	2003
Domestic equity securities	38%	40%
International equity securities	10	10
Debt securities	52	49
Cash	--	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 targets 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 $15 million to its postretirement benefits plan in 2004.

(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 $3 million, $6 million and $5 million in 2001, 2002 and 2003, 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 2001, 2002 and 2003, 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, 2002 and 2003, was $13 million and $10 million, respectively, relating to deferred compensation plans.

(f) OTHER EMPLOYEE MATTERS

As of December 31, 2003, approximately 28% of the Company's employees are subject to collective bargaining agreements. Two of these agreements, covering approximately 9% of the Company's employees, have expired or will expire in 2004.

The Minnegasco division of the Company's natural gas distribution business has 512 bargaining unit employees that are covered by collective bargaining unit agreements that have expired or will expire in 2004. An agreement with the International Brotherhood of Electrical Workers Local 949, which expired in December 2003, was renegotiated in February 2004 covering 267 of these employees. The remaining 245 employees are covered by a collective bargaining agreement with the Office and Professional Employees International Union Local 12, which expires in May 2004.

8. INCOME TAXES

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

	YEAR ENDED DECEMBER 31,		
	2001	2002	2003
	(IN MILLIONS)		
Current			
Federal	$ 31	$ 56	$ 30
State	(3)	9	4
Total current	28	65	34
Deferred			
Federal	29	12	11
State	1	11	14
Total deferred	30	23	25
Income tax expense	$ 58	$ 88	$ 59

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

	YEAR ENDED DECEMBER 31,		
	2001	2002	2003
	(IN MILLIONS)		
Income before income taxes	$ 125	$ 208	$ 188
Federal statutory rate	35%	35%	35%
Income tax expense at statutory rate	44	73	66
Increase (decrease) in tax resulting from:			
Capital loss benefit	--	(72)	--
State income taxes, net of valuation allowances and federal income tax benefit (1)	(1)	13	12
Goodwill amortization	16	--	--
Valuation allowance, capital loss	--	72	--
Changes in estimates for prior year items	--	--	(19)
Other, net	(1)	2	--
Total	14	15	(7)
Income tax expense	$ 58	$ 88	$ 59
Effective Rate	46.4%	42.2%	31.3%

- ----------

(1) Calculation of the accrual for state income taxes at the end of each year requires that the Company estimate

the manner in which its income for that year will be allocated and/or apportioned among the various states in which it conducts business, where states have widely differing tax rules and rates. These allocation/apportionment factors change from year to year and the amount of taxes ultimately payable may differ from that estimated as a part of the accrual process. For these reasons, the amount of state income tax expense may vary significantly from year to year, even in the absence of significant changes to state income tax valuation allowances or changes in individual state income tax rates.

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, 2002	DECEMBER 31, 2003
	(IN MILLIONS)	
Deferred tax assets:		
Current:		
Current portion of capital loss	$ 8	$ --
Allowance for doubtful accounts	9	9
Total current deferred tax assets	17	9
Non-current:		
Employee benefits	79	63
Operating and capital loss carryforwards	86	81
Deferred gas costs	--	18
Other	50	52
Valuation allowance	(83)	(73)
Total non-current deferred tax assets	132	141
Total deferred tax assets	149	150
Deferred tax liabilities:		
Current:		
Non-trading derivative liabilities, net	7	18
Total current deferred tax liabilities	7	18
Non-current:		
Depreciation	685	746
Deferred gas costs	3	--
Other	50	40
Total non-current deferred tax liabilities	738	786
Total deferred tax liabilities	745	804
Accumulated deferred income taxes, net	$ 596	$ 654

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 2000 consolidated federal income tax returns are currently under audit.

Tax Attribute Carryforwards. At December 31, 2003, the Company had $348 million of state tax net operating loss carryforwards. The loss carryforwards are available to offset future state taxable income through the year 2022. Substantially all of the state loss carryforwards will expire between 2014 and 2020. The Company also had $206 million of capital loss carryforwards which will expire in 2007.

The valuation allowance reflects a net increase of $68 million in 2002 and a net decrease of $10 million in 2003. These net changes resulted from a reassessment of the Company's future ability to use federal capital loss carryforwards and state tax net operating loss carryforwards.

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 2004 and 2008 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, 2003 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 $1 billion in 2004, $565 million in 2005, $344 million in 2006, $171 million in 2007 and $24 million in 2008.

(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):

2004................	$	25
2005................		10
2006................		8
2007................		4
2008................		3
2009 and beyond.....		10
Total.....	$	60

Total rental expense for all operating leases was $31 million, $31 million and $28 million in 2001, 2002 and 2003, 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 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 CERC 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.

Gas Cost Recovery Litigation. In October 2002, a suit was filed in state district court in Wharton County, Texas against CenterPoint Energy, the Company, Entex Gas Marketing Company, and others 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. The plaintiffs seek class certification, but no class has been certified. The plaintiffs allege that defendants inflated the prices charged to certain consumers of natural gas. In February 2003, a similar suit was filed against the Company in state court in Caddo Parish, Louisiana purportedly on behalf of a class of residential or business customers in Louisiana who allegedly have been overcharged for gas or gas service provided by the Company. In February 2004, another suit was filed against the Company in Calcasieu Parish, Louisiana, seeking to recover alleged overcharges for gas or gas services allegedly provided by Entex without advance approval by the LPSC. The plaintiffs in these cases seek injunctive and declaratory relief, restitution for the alleged overcharges, exemplary damages or trebling of actual damages and civil penalties. In these cases, CenterPoint Energy, the Company and Entex Gas Marketing Company 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.

(D) ENVIRONMENTAL MATTERS

Hydrocarbon Contamination. CERC Corp. and certain of its subsidiaries are among some of 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 quantity of monetary damages sought is unspecified. The Company is unable to estimate the monetary damages, if any, that the plaintiffs may be awarded in these matters.

Manufactured Gas Plant Sites. The Company and its predecessors operated manufactured gas plants (MGP) in the past. In Minnesota, remediation has been completed on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in the Company's Minnesota service territory, two of which it believes were neither owned nor operated by the Company, and for which it believes it has no liability.

At December 31, 2003, the Company had accrued $19 million for remediation of certain Minnesota sites. At December 31, 2003, the estimated range of possible remediation costs for these sites was $8 million to $44 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. The Company has collected or accrued $12.5 million as of December 31, 2003 to be used for environmental remediation.

The Company has received notices from the United States Environmental Protection Agency and others regarding its status as a PRP for other sites. The Company has been named as a defendant in lawsuits under which contribution is sought 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 is investigating details regarding these sites and the range of environmental expenditures for potential remediation. Based on current information, the Company has not been able to quantify a range of environmental expenditures for such sites.

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. The Company anticipates that additional claims like those received may be asserted in the future and intends to continue vigorously contesting claims which it does not consider to have merit. Although their ultimate outcome 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

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 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, 2002 and 2003 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, 2002		DECEMBER 31, 2003	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Financial liabilities:				
Long-term debt (excluding capital leases)....	$ 1,959	$ 2,069	$ 2,371	$ 2,612

11. UNAUDITED QUARTERLY INFORMATION

Summarized quarterly financial data is as follows:

	YEAR ENDED DECEMBER 31, 2002			
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN MILLIONS)			
Revenues............	$ 1,242	$ 868	$ 737	$ 1,361
Operating income....	143	48	37	125
Net income (loss)...	69	8	(5)	48

	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

12. REPORTABLE SEGMENTS

Because CERC Corp. is an indirect wholly owned subsidiary of CenterPoint Energy, the Company's 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.

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 for, residential, commercial and industrial customers, and some non-rate regulated retail gas marketing operations. Pipelines and Gathering includes the interstate natural gas pipeline operations and natural gas gathering and pipeline services. Other Operations includes unallocated general corporate expenses and non-operating investments. All of the Company's long-lived assets are in the United States.

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

	NATURAL GAS DISTRIBUTION	PIPELINES AND GATHERING	OTHER OPERATIONS	RECONCILING ELIMINATIONS	SALES TO AFFILIATES	CONSOLIDATED
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2001:						
Revenues from external customers(1)	4,737	307	--	--	--	5,044
Intersegment revenues	5	108	--	(113)	--	--
Depreciation and amortization	147	58	2	--	--	207
Operating income (loss)	130	137	(1)	--	--	266
Total assets	4,083	2,379	101	(182)	--	6,381
Expenditures for long-lived assets	209	54	--	--	--	263
AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2002:						
Revenues from external customers(1)	3,927	253	--	--	28	4,208
Intersegment revenues	33	121	--	(154)	--	--
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	5,378	241	--	--	31	5,650
Intersegment revenues	57	166	9	(232)	--	--
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

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(1) Included in revenues from external customers are revenues from sales to Reliant Resources, a former affiliate, of $181 million and $42 million for the years ended December 31, 2001 and 2002, respectively.

	YEAR ENDED DECEMBER 31, 2001	2002	2003
	(IN MILLIONS)		
REVENUES BY PRODUCTS AND SERVICES:			
Retail gas sales	$ 4,645	$ 3,857	$ 5,310
Gas transportation	307	255	244
Energy products and services	92	96	96
Total	$ 5,044	$ 4,208	$ 5,650

INDEPENDENT AUDITORS' REPORT

To the Stockholder of CenterPoint Energy Resources Corp.:

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp., formerly Reliant Energy Resources Corp., and its subsidiaries (the Company) as of December 31, 2002 and 2003, and the related consolidated statements of income, comprehensive income, stockholder's equity and cash flows for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedule listed in the Index at Item 15(a)(2). These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 2(d) to the consolidated financial statements, on January 1, 2002, the Company changed its method of accounting for goodwill and certain intangible assets to conform to Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets."

DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2004

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

None.

ITEM 9A. 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, 2003 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, 2003 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS.

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 STOCKHOLDERS 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, 2002 and 2003 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, 2002	2003
Audit fees	$667,000	$864,259
Audit-related fees	95,100	53,935
Total audit and audit-related fees	762,100	918,194
Tax fees	--	--
All other fees	--	--
Total fees	$762,100	$918,194

(1) Agreed upon procedures related to our receivables facility.

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

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a)(1) Financial Statements.	
Statements of Consolidated Income for the Three Years Ended December 31, 2003	21
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2003	22
Consolidated Balance Sheets at December 31, 2003 and 2002	23
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2003	24
Statements of Consolidated Shareholders' Equity for the Three Years Ended December 31, 2003	25
Notes to Consolidated Financial Statements	26
Independent Auditors' Report	46
(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2003.	
II -- Qualifying Valuation Accounts	49

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 on page 51.

(b) Reports on Form 8-K

On October 29, 2003, we filed a Current Report on Form 8-K dated October 29, 2003 in which we furnished information under Item 12 of that form relating to our third quarter 2003 financial results.

On November 5, 2003, we filed a Current Report on Form 8-K dated October 29, 2003 announcing the pricing and closing of $160 million of our senior notes in a private placement with institutions pursuant to Rule 144A under the Securities Act of 1933, as amended, and Regulation S. The notes bear interest at a rate of 5.95% and will be due January 15, 2014.

On March 3, 2004, we filed a Current Report on Form 8-K dated March 3, 2004 to furnish under Item 9 of that form a slide presentation we expect will be presented to various members of the financial and investment community from time to time.

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, 2003

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E
		ADDITIONS		
DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO INCOME	DEDUCTIONS FROM RESERVES(1)	BALANCE AT END OF PERIOD
		(IN THOUSANDS)		
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
Year Ended December 31, 2001:				
Accumulated provisions:				
Uncollectible accounts receivable........	32,375	45,745	45,073	33,047
Deferred tax asset valuation allowance...	47,677	(32,678)	--	14,999

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(1) 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 12th day of March, 2004.

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 12, 2004.

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, 2003

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(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(e)(9)	--	Registration Rights Agreement dated as of November 3, 2003, among CERC Corp. and the initial purchasers named therein relating to CERC Corp.'s 5.95% Senior Notes due 2014	Form 8-K dated October 29, 2003	1-13265	4(i)
4(f)(1)	--	Revolving Credit Agreement among NorAm Energy Corp. and the Bank's party thereto and Citibank, N.A., as Agent dated as of March 31, 1998	Form 10-K for the year ended December 31, 2001	1-3187	4(g)1
4(f)(2)	--	Amendment Agreement dated as of March 23, 1999 among RERC Corp., the lenders parties thereto, The Bank of Nova Scotia, as issuing Bank, and Citibank, N.A., as Agent	Form 10-K for the year ended December 31, 2001	1-3187	4(g)2

EXHIBIT NUMBER		DESCRIPTION	REPORT OR REGISTRATION STATEMENT	SEC FILE OR REGISTRATION NUMBER	EXHIBIT REFERENCE
4(f)(3)	--	Second Amendment Agreement and Consent dated as of August 22, 2000 among RERC Corp., the lenders party thereto, The Bank of Nova Scotia, as Issuing Bank, and Citibank, N.A., as Agent	Form 10-K for the year ended December 31, 2001	1-3187	4(g)3
4(f)(4)	--	Third Amendment Agreement and Consent, dated as of July 13, 2001, among RERC Corp., the lenders party thereto, The Bank of Nova Scotia, as Issuing Bank, and Citibank, N.A., as Agent	Form 10-K for the year ended December 31, 2001	1-3187	4(g)4

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
10(b)	--	$200,000,000 Credit Agreement, dated as of March 25, 2003, among CERC Corp., as borrower, and the banks named therein	Form 10-Q for the quarter ended March 31, 2003	1-13265	4(a)
+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,				
	1999	2000	2001	2002	2003
Income from continuing operations	$ 103,871	$ 98,228	$ 67,244	$ 120,060	$ 128,878
Income taxes for continuing operations	88,781	93,272	58,287	87,643	58,706
Minority interest expense (income)	--	(37)	(36)	11	(55)
Capitalized interest	(1,908)	(1,982)	(185)	(1,202)	(851)
	190,744	189,481	125,310	206,512	186,678
Fixed charges, as defined:					
Interest expense	119,500	142,861	154,965	153,688	178,973
Capitalized interest	1,908	1,982	185	1,202	851
Distribution on trust preferred securities	357	29	28	25	12
Interest component of rentals charged to operating expense	10,975	10,934	10,369	10,188	9,252
Total fixed charges	132,740	155,806	165,547	165,103	189,088
Earnings, as defined	$ 323,484	$ 345,287	$ 290,857	$ 371,615	$ 375,766
Ratio of earnings to fixed charges	2.44	2.22	1.76	2.25	1.99

EXHIBIT 23

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement No. 333-54256 of CenterPoint Energy Resources Corp. on Form S-3 of our report dated March 12, 2004 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the change in method of accounting for goodwill and certain intangible assets) appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2003.

DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2004

EXHIBIT 31.1

CERTIFICATION

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 officers 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 officers 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 12, 2004

By: /s/ David M. McClanahan

David M. McClanahan
Chairman, President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

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 officers 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 officers 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 12, 2004

By: /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 period ending December 31, 2003 (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
- ---
David M. McClanahan
Chairman, President and Chief Executive Officer
March 12, 2004

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 period ending December 31, 2003 (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
- --
Gary L. Whitlock
Executive Vice President and Chief Financial Officer
March 12, 2004