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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2007

or

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

For the transition period from __________ to __________

Commission File Number 1-13265

CenterPoint Energy Resources Corp.
(Exact name of registrant as specified in its charter)

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

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

Title of Each Class	Name of Each Exchange On Which Registered
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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ☑

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 ☑ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of 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. ☑

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ☑ (Do not check if a smaller reporting company)	Smaller Reporting Company o

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act).Yes o No ☑

The aggregate market value of the common equity held by non-affiliates as of June 30, 2007: None

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We meet the conditions specified in General Instruction I(1)(a) and (b) of Form 10-K and are thereby permitted to use the reduced disclosure format for wholly owned subsidiaries of reporting companies specified therein. Accordingly, we have omitted from this report the information called for by Item 4 (Submission of Matters to a Vote of Security Holders), Item 10 (Directors, Executive Officers, and Corporate Governance), Item 11 (Executive Compensation), Item 12 (Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters) and Item 13 (Certain Relationships and Related Transactions, and Director Independence) 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, Management's Narrative Analysis of the Results of Operations to explain the reasons for material changes in the amount of revenue and expense items between 2005, 2006 and 2007.

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" in Item 1A 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.

PART I

Item 1. *Business*

OUR BUSINESS

Overview

We own and operate natural gas distribution systems in six states. Subsidiaries of ours own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of ours offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities. References to “we,” “us,” and “our” mean CenterPoint Energy Resources Corp. (CERC Corp., together with our subsidiaries, CERC). We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

Our reportable business segments are Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations.

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

We make available free of charge on our parent company’s Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the Securities and Exchange Commission (SEC). Our parent company’s website address is *www.centerpointenergy.com*. Except to the extent explicitly stated herein, documents and information on our parent company’s website are not incorporated by reference herein.

Natural Gas Distribution

Our natural gas distribution business (Gas Operations) engages in regulated intrastate natural gas sales to, and natural gas transportation for, approximately 3.2 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. The largest metropolitan areas served in each state by Gas Operations are Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. In 2007, approximately 43% of Gas Operations’ total throughput was attributable to residential customers and approximately 57% was attributable to commercial and industrial customers.

Gas Operations also provides unregulated services consisting of heating, ventilating and air conditioning (HVAC) equipment and appliance repair, and sales of HVAC, hearth and water heating equipment in Minnesota.

The demand for intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers is seasonal. In 2007, approximately 71% of the total throughput of Gas Operations’ business occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during those periods.

Supply and Transportation. In 2007, Gas Operations purchased virtually all of its natural gas supply pursuant to contracts with remaining terms varying from a few months to four years. Major suppliers in 2007 included BP Canada Energy Marketing Corp. (21.0% of supply volumes), Oneok Energy Marketing (14.7%), Energy Transfer (10.3%), Coral Energy Resources (9.8%) and Tenaska Marketing Ventures (7.8%). Numerous other suppliers provided the remaining 36.4% of Gas Operations’ natural gas supply requirements. Gas Operations transports its natural gas supplies through various intrastate and interstate pipelines, including those owned by our other subsidiaries, under contracts with remaining terms, including extensions, varying from one to fifteen years. Gas Operations anticipates that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

We actively engage in commodity price stabilization pursuant to annual gas supply plans presented to and/or filed with each of our state regulatory authorities. These price stabilization activities include use of storage gas, contractually establishing fixed prices with our physical gas suppliers and utilizing financial derivative instruments to achieve a variety of pricing structures (e.g., fixed price, costless collars, and caps). Our gas supply plans generally call for 25-50% of winter supplies to be hedged in some fashion.

Generally, the regulations of the states in which Gas Operations operates allow it to pass through changes in the cost of natural gas, including gains and losses on financial derivatives associated with the index-priced physical supply, to its customers under purchased gas adjustment provisions in its tariffs. Depending upon the jurisdiction, the purchased gas adjustment factors are updated periodically, ranging from monthly to semi-annually, using estimated gas costs. The changes in the cost of gas billed to customers are subject to review by the applicable regulatory bodies.

Gas Operations uses various third-party storage services or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather and may also supplement contracted supplies and storage from time to time with stored liquefied natural gas and propane-air plant production.

Gas Operations owns and operates an underground natural gas storage facility with a capacity of 7.0 billion cubic feet (Bcf). It has a working capacity of 2.0 Bcf available for use during a normal heating season and a maximum daily withdrawal rate of 50 million cubic feet (MMcf). It also owns nine propane-air plants with a total production rate of 200 MMcf per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf natural gas equivalent). It owns liquefied natural gas plant facilities with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf natural gas equivalent) and a production rate of 72 MMcf per day.

On an ongoing basis, Gas Operations enters into contracts to provide sufficient supplies and pipeline capacity to meet its 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.

Assets

As of December 31, 2007, Gas Operations owned approximately 69,000 linear miles of natural gas distribution mains, varying in size from one-half inch to 24 inches in diameter. Generally, in each of the cities, towns and rural areas served by Gas Operations, it owns 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 Gas Operations receives gas are owned, operated and maintained by others, and its 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

Gas Operations competes 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 regulations affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass Gas Operations' facilities and market and sell and/or transport natural gas directly to commercial and industrial customers.

Competitive Natural Gas Sales and Services

We offer variable and fixed-priced physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities through CenterPoint Energy Services, Inc. (CES) and its subsidiary, CenterPoint Energy Intrastate Pipeline LLC (CEIP).

In 2007, CES marketed approximately 522 Bcf of natural gas, transportation and related energy services to approximately 7,000 customers (including approximately 9 Bcf to affiliates). CES customers vary in size from small commercial customers to large utility companies in the central and eastern regions of the United States, and are served from offices located in Illinois, Indiana, Louisiana, Minnesota, Missouri, Pennsylvania, Texas and Wisconsin. The business has three operational functions: wholesale, retail and intrastate pipelines, which are further described below.

Wholesale Operations. CES offers a portfolio of physical delivery services and financial products designed to meet wholesale customers' supply and price risk management needs. These customers are served directly through interconnects with various inter- and intra-state pipeline companies, and include gas utilities, large industrial customers and electric generation customers.

Retail Operations. CES offers a variety of natural gas management services to smaller commercial and industrial customers, municipalities, educational institutions and hospitals, whose facilities are located downstream of natural gas distribution utility city gate stations. These services include load forecasting, supply acquisition, daily swing volume management, invoice consolidation, storage asset management, firm and interruptible transportation administration and forward price management. CES manages transportation contracts and energy supply for retail customers in sixteen states.

Intrastate Pipeline Operations. CEIP primarily provides transportation services to shippers and end-users and contracts out approximately 2 Bcf of storage at its Pierce Junction facility in Texas.

CES currently transports natural gas on over 34 interstate and intrastate pipelines within states located throughout the central and eastern United States. CES maintains a portfolio of natural gas supply contracts and firm transportation and storage agreements to meet the natural gas requirements of its customers. CES aggregates supply from various producing regions and offers contracts to buy natural gas with terms ranging from one month to over five years. In addition, CES actively participates in the spot natural gas markets in an effort to balance daily and monthly purchases and sales obligations. Natural gas supply and transportation capabilities are leveraged through contracts for ancillary services including physical storage and other balancing arrangements.

As described above, CES offers its customers a variety of load following services. In providing these services, CES uses its customers' purchase commitments to forecast and arrange its own supply purchases, storage and transportation services to serve customers' natural gas requirements. As a result of the variance between this forecast activity and the actual monthly activity, CES will either have too much supply or too little supply relative to its customers' purchase commitments. These supply imbalances arise each month as customers' natural gas requirements are scheduled and corresponding natural gas supplies are nominated by CES for delivery to those customers. CES' processes and risk control environment are designed to measure and value imbalances on a real-time basis to ensure that CES' exposure to commodity price risk is kept to a minimum. The value assigned to these imbalances is calculated daily and is known as the aggregate Value at Risk (VaR). In 2007, CES' VaR averaged $1.2 million with a high of $2.6 million.

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

Assets

CEIP owns and operates approximately 217 miles of intrastate pipeline in Louisiana and Texas and holds storage facilities of approximately 2 Bcf in Texas under long-term leases. In addition, CES leases transportation capacity of approximately 725 MMcf per day on various inter- and intrastate pipelines and approximately 8.5 Bcf of storage to service its customer base.

Competition

CES competes with regional and national wholesale and retail gas marketers including the marketing divisions of natural gas producers and utilities. In addition, CES competes with intrastate pipelines for customers and services in its market areas.

Interstate Pipelines

Our pipelines business operates interstate natural gas pipelines with gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. Our interstate pipeline operations are primarily conducted by two wholly owned subsidiaries that 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; and
- 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.

The rates charged by CEGT and MRT for interstate transportation and storage services are regulated by the Federal Energy Regulatory Commission (FERC). Our interstate pipelines business operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

In 2007, approximately 20% of CEGT and MRT's total operating revenue was attributable to services provided to Gas Operations and approximately 10% was attributable to services provided 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 Gas Operations and Laclede are provided under several long-term firm storage and transportation agreements. Since October 31, 2006, MRT's contract with Laclede has been terminable upon one year's prior notice. MRT has not received a termination notice and is currently negotiating a long-term contract with Laclede. Agreements for firm transportation, "no notice" transportation service and storage service in certain of Gas Operations' service areas (Arkansas, Louisiana and Oklahoma) expire in 2012.

Carthage to Perryville. In April 2007, CEGT, our wholly owned subsidiary, completed phase one construction of a 172-mile, 42-inch diameter pipeline and related compression facilities for the transportation of gas from Carthage, Texas to CEGT's Perryville hub in northeast Louisiana. On May 1, 2007, CEGT began service under its firm transportation agreements with shippers of approximately 960 MMcf per day. CEGT's second phase of the project, which involved adding compression that increased the total capacity of the pipeline to approximately 1.25 Bcf per day, was placed into service in August 2007. CEGT has signed firm contracts for the full capacity of phases one and two.

In May 2007, CEGT received FERC approval for the third phase of the project to expand capacity of the pipeline to 1.5 Bcf per day by adding additional compression and operating at higher pressures, and in July 2007, CEGT received approval from the Pipeline and Hazardous Materials Administration (PHMSA) to increase the maximum allowable operating pressure. The PHMSA's approval contained certain conditions and requirements, which CEGT expects to satisfy in the first quarter of 2008. CEGT has executed contracts for approximately 150 MMcf per day of the 250 MMcf per day phase three expansion. The third phase is projected to be in-service in the second quarter of 2008.

In September 2007, CEGT initiated an investigation into allegations received from two former employees of the manufacturer of pipe installed in CEGT's Carthage to Perryville pipeline segment. That pipeline segment was placed in commercial service in May 2007 after satisfactory completion of hydrostatic testing designed to ensure that the pipe and its welds would be structurally sound when placed in service and operated at design pressure. According to the complainants, records relating to radiographic inspections of certain welds made at the fabrication facility had been altered resulting in the possibility that pipe with alleged substandard welds had been installed in the pipeline. In conducting its investigation, among other things, CEGT and its counsel interviewed the complainants and other individuals, including CEGT and contractor personnel, and reviewed documentation related to the manufacture and construction of the pipeline, including radiographic records related to the allegedly deficient welds. CEGT kept appropriate governmental officials informed throughout its investigation and consulted appropriate technical consultants and pre-existing regulatory guidance. CEGT excavated and inspected certain welds at the request of the PHMSA, and in each case, CEGT found those welds to be structurally sound. Although its investigation has not been formally concluded, CEGT has worked closely with the appropriate regulatory authorities to determine and take all necessary actions. To date, CEGT has found no reason to modify the operation of its Carthage to Perryville line or take other significant action, and no such action has been directed or requested by any governmental authority. Absent new evidence, CEGT believes that no significant action by CEGT will be necessary and that the Carthage to Perryville line can be operated at expected operating pressures without threat to the public health or safety and does not plan to take any significant additional action.

Southeast Supply Header. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., our wholly owned subsidiary, and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture (Southeast Supply Header or SESH) to construct, own and operate a 270-mile pipeline with a capacity of approximately 1 Bcf per day that will extend from CEGT's Perryville hub in northeast Louisiana to an interconnection in southern Alabama with Gulfstream Natural Gas System, which is 50% owned by an affiliate of Spectra. We account for our 50% interest in SESH as an equity investment. In 2006, SESH signed agreements with shippers for firm transportation services, which subscribed capacity of 945 MMcf per day. Additionally, SESH and Southern Natural Gas (SNG) have executed a definitive agreement that provides for SNG to jointly own the first 115 miles of the pipeline. Under the agreement, SNG will own an undivided interest in the portion of the pipeline from Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter was increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that will increase the jointly owned capacity up to 500 MMcf per day, subject to FERC approval.

An application to construct, own and operate the pipeline was filed with the FERC in December 2006. In September 2007, the FERC issued the certificate authorizing the construction of the pipeline. This FERC approval does not include the expansion capacity that would take SNG to 500 MMcf per day. SESH began construction in November 2007. SESH expects to complete construction of the pipeline as approved by the FERC in the second half of 2008. SESH's net costs after SNG's contribution are estimated to have increased to approximately $1 billion.

Assets

Our interstate pipelines business currently owns and operates approximately 8,100 miles of natural gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. It also owns and operates 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. It also owns a 10% interest in the Bistineau storage facility located in Bienville Parish, Louisiana, with the remaining interest owned and operated by Gulf South Pipeline Company, LP. This facility has a total working gas capacity of 85.7 Bcf and approximately 1.1 Bcf per day of deliverability. Storage capacity in the Bistineau facility is 8 Bcf of working gas with 100 MMcf per day of deliverability. Most storage operations are in north Louisiana and Oklahoma.

Competition

Our interstate pipelines business competes with other interstate and intrastate pipelines 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 interstate pipelines business competes indirectly with other forms of energy available to our customers, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability of energy and pipeline capacity, the level of business activity, conservation and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas in areas we serve and the level of competition for transportation and storage services.

Field Services

Our field services business operates gas gathering, treating, and processing facilities and also provides operating and technical services and remote data monitoring and communication services.

Our field services operations are conducted by a wholly owned subsidiary, CenterPoint Energy Field Services, Inc. (CEFS). CEFS provides natural gas gathering and processing services for certain natural gas fields in the Mid-continent region of the United States that interconnect with CEGT's and MRT's pipelines, as well as other interstate and intrastate pipelines. CEFS gathers approximately 1.1 Bcf per day of natural gas and, either directly or through its 50% interest in the Waskom Joint Venture, processes in excess of 240 MMcf per day of natural gas along its gathering system. CEFS, through its ServiceStar operating division, provides remote data monitoring and communications services to affiliates and third parties. As of the end of 2007, ServiceStar provided monitoring activities at approximately 12,500 locations across Alabama, Arkansas, Colorado, Illinois, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, Texas and Wyoming, but has reduced that total by approximately 2,300 units in 2008 as a result of an agreement reached between CEFS and ServiceStar's largest customer to revise certain contractual arrangements between them, including termination of ServiceStar's monitoring services for that customer.

Our field services business operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

Assets

Our field services business owns and operates approximately 3,500 miles of gathering pipelines and processing plants that collect, treat and process natural gas from approximately 151 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Competition

Our field services business competes with other companies in the natural gas gathering, treating, and processing business. The principal elements of competition are rates, terms of service and reliability of services. Our field services business competes indirectly with other forms of energy available to our customers, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability of energy and pipeline capacity, the level of business activity, conservation and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas in areas we serve and the level of competition for gathering, treating, and processing 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

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

Financial Information About Segments

For financial information about our segments, see Note 11 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.

Federal Energy Regulatory Commission

The FERC has jurisdiction under the Natural Gas Act and the Natural Gas Policy Act of 1978, as amended, to regulate the transportation of natural gas in interstate commerce and natural gas sales for resale in intrastate commerce that are not first sales. The FERC regulates, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. The rates charged by interstate pipelines for interstate transportation and storage services are also regulated by the FERC. The Energy Policy Act of 2005 (Energy Act) expanded the FERC's authority to prohibit market manipulation in connection with FERC-regulated transactions and gave the FERC additional authority to impose significant civil and criminal penalties for statutory violations and violations of the FERC's rules or orders and also expanded criminal penalties for such violations. Our competitive natural gas sales and services subsidiary markets natural gas in interstate commerce pursuant to blanket authority granted 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.

Under the Public Utility Holding Company Act of 2005 (PUHCA 2005), the FERC has authority to require holding companies and their subsidiaries to maintain certain books and records and make them available for review by the FERC and state regulatory authorities in certain circumstances. In December 2005, the FERC issued rules implementing PUHCA 2005. Pursuant to those rules, in June 2006, CenterPoint Energy filed with the FERC the required notification of its status as a public utility holding company. In October 2006, the FERC adopted additional rules regarding maintenance of books and records by utility holding companies and additional reporting and accounting requirements for centralized service companies that make allocations to public utilities regulated by the FERC under the Federal Power Act. Although CenterPoint Energy provides services to its subsidiaries through a service company, its service company is not subject to the FERC's service company rules.

State and Local Regulation

In almost all communities in which Gas Operations provides natural gas distribution services, it operates under franchises, certificates or licenses obtained from state and local authorities. The original terms of the franchises, with various expiration dates, typically range from 10 to 30 years, although franchises in Arkansas are perpetual. Gas Operations expects to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of Gas Operations is subject to cost-of-service regulation by the relevant state public utility commissions and, in Texas, by the Railroad Commission of Texas (Railroad Commission) and those municipalities Gas Operations serves that have retained original jurisdiction.

Arkansas. In January 2007, Gas Operations filed an application with the Arkansas Public Service Commission (APSC) to change its natural gas distribution rates in order to increase its annual base revenues by approximately $51 million. Gas Operations subsequently agreed to reduce its request to approximately $40 million. As part of its filing, Gas Operations also proposed a revenue stabilization tariff (also known as decoupling) that would help stabilize revenues and eliminate the potential conflict between its efforts to earn a reasonable return on invested capital while promoting energy efficiency initiatives.

In September 2007, the APSC staff and Gas Operations entered into and filed with the APSC a Stipulation and Settlement Agreement (Settlement Agreement) under which the annual base revenues of Gas Operations would increase by approximately $20 million, and a revenue stabilization tariff would be allowed to go into effect, with an authorized rate of return on equity of 9.65% (reflecting a 10 basis point reduction for the implementation of the revenue stabilization tariff). The other parties to the proceeding agreed not to oppose the Settlement Agreement. In October 2007, the APSC issued an order approving the Settlement Agreement, and the new rates became effective with bills rendered on and after November 1, 2007.

Texas. In December 2006, Gas Operations filed a statement of intent with the Railroad Commission of Texas (Railroad Commission) seeking to implement an increase in miscellaneous service charges and to allow recovery of the costs of financial hedging transactions through its purchased gas cost adjustment in the environs of its Texas Coast service territory. After approval of the filing by the Railroad Commission, the new service charges were implemented in the second quarter of 2007.

In response to an explosion resulting from the failure of a certain type of compression coupling on another company's natural gas distribution system in Texas, the Railroad Commission has begun a rulemaking focusing on leak surveys, leak grading and the replacement of specific types of compression couplings. In addition, the Railroad Commission issued a directive in November 2007 requiring the removal of service risers known to have compression fittings that do not meet certain performance specifications. After reviewing our records as required by the directive, Gas Operations has no indication that we have the type of coupling described in that directive. However, at this time we do not know what additional requirements may result from the pending Railroad Commission rulemaking or what impacts on our gas operations may result from any future regulatory initiatives adopted with respect to this issue.

In the first quarter of 2008, Gas Operations filed a request to change its rates with the Railroad Commission and the 47 cities in its Texas Coast service territory. The request seeks to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Texas Coast service territory. The effect of the requested rate changes will be to increase the Texas Coast service territory's revenues by approximately $7 million per year.

Minnesota. In November 2005, Gas Operations filed a request with the Minnesota Public Utilities Commission (MPUC) to increase annual base rates by approximately $41 million. In December 2005, the MPUC approved an interim rate increase of approximately $35 million that was implemented January 1, 2006. In January 2007, the MPUC issued a final order granting a rate increase of approximately $21 million and approving a $5 million affordability program to assist low-income customers, the actual cost of which will be recovered in rates in addition to the $21 million rate increase. Final rates were implemented beginning May 1, 2007, and Gas Operations completed refunding to customers the proportional share of the excess of the amounts collected in interim rates over the amount allowed by the final order in the second quarter of 2007.

In November 2006, the MPUC denied a request filed by Gas Operations for a waiver of MPUC rules in order to allow Gas Operations to recover approximately $21 million in unrecovered purchased gas costs related to periods prior to July 1, 2004. Those unrecovered gas costs were identified as a result of revisions to previously approved calculations of unrecovered purchased gas costs. Following that denial, Gas Operations recorded a $21 million adjustment to reduce pre-tax earnings in the fourth quarter of 2006 and reduced the regulatory asset related to these costs by an equal amount. In March 2007, following the MPUC's denial of reconsideration of its ruling, Gas Operations petitioned the Minnesota Court of Appeals for review of the MPUC's decision. That court heard oral arguments on the appeal in February 2008 and is expected to render its decision within 90 days of that hearing. No prediction can be made as to the ultimate outcome of this matter.

Department of Transportation

In December 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (2002 Act). This legislation applies to our interstate pipelines as well as our intrastate pipeline 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 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, which reauthorized the programs adopted under the 2002 Act, proposed enhancements for state programs to reduce excavation damage to pipelines, established increased federal enforcement of one-call excavation programs, and established a new program for review of pipeline security plans and critical facility inspections. In addition, beginning in October 2005, the PHMSA of the U.S. Department of Transportation (DOT) commenced a rulemaking proceeding to develop rules that would better distinguish onshore gathering lines from production facilities and transmission lines, and to develop safety requirements better tailored to gathering line risks. In March 2006, the DOT revised its regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in non-rural areas, and adopt new compliance deadlines.

We anticipate that compliance with these regulations by our interstate and intrastate pipelines and our natural gas distribution companies will require increases in both capital and operating costs. 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 believe compliance will require average annual expenditures of approximately $15 to $20 million during the initial 10-year period.

ENVIRONMENTAL MATTERS

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

- restricting the way we can handle or dispose of wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations, or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

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

- construct or acquire new equipment;
- acquire permits for facility operations;
- modify or replace existing and proposed equipment; and
- clean up or decommission waste disposal areas, fuel storage and management facilities and other locations and facilities.

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

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

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

Global Climate Change

In recent years, there has been increasing public debate regarding the potential impact on global climate change by various "greenhouse gases" such as carbon dioxide, a byproduct of burning fossil fuels, and methane, a component of the natural gas which we transport and deliver to customers. Legislation to regulate emissions of greenhouse gases has been introduced in Congress, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industries such as the utility industry to meet stringent new standards requiring substantial reductions in carbon emissions. Those reductions could be costly and difficult to implement. Some proposals would provide for credits to those who reduce emissions below certain levels and would allow those credits to be traded and/or sold to others. It is too early to determine whether, and in what form, a regulatory scheme regarding greenhouse gas emissions will be adopted or what specific impacts a new regulatory scheme might have on us and our subsidiaries. However, as a distributor and transporter of natural gas and consumer of natural gas in our pipeline and gathering businesses, our revenues, operating costs and capital requirements could be adversely affected.

Air Emissions

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

Water Discharges

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

Hazardous Waste

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

Liability for Remediation

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

Liability for Preexisting Conditions

Hydrocarbon Contamination. We and certain of our subsidiaries were among the defendants in lawsuits filed beginning in August 2001 in Caddo Parish and Bossier Parish, Louisiana. The suits alleged 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 was 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 our predecessor in interest. This facility was purportedly used for gathering natural gas from surrounding wells, separating liquid hydrocarbons from the natural gas for marketing, and transmission of natural gas for distribution.

In July 2007, the parties implemented the terms of an agreed settlement and resolved this matter. Pursuant to the agreed terms, we entered into a cooperative agreement with the Louisiana Department of Environmental Quality (LDEQ), pursuant to which we will work with the LDEQ to develop a remediation plan that could be implemented by us. As part of the settlement, we made a payment within the amounts previously reserved for this matter. We do not expect the costs associated with the resolution of this matter to have a material impact on our financial condition, results of operations or cash flows.

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

At December 31, 2007, we had accrued $14 million for remediation of these Minnesota sites. At December 31, 2007, the estimated range of possible remediation costs for these sites was $4 million to $35 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. We have utilized an environmental expense tracker mechanism in our rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2007, we had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the EPA and other regulators have investigated MGP sites that were owned or operated by us or may have been owned by one of our former affiliates. We have been named as a defendant in a lawsuit, filed in the United States District Court, District of Maine under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of ours or our divisions. We have also been identified as a PRP by the State of Maine for a site that is the subject of the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including us, would have to contribute to that remediation. We are investigating details regarding this site and the range of environmental expenditures for potential remediation. However, we believe we are not liable as a former owner or operator of the site under CERCLA and applicable state statutes, and are vigorously contesting the suit and our designation as a PRP.

Mercury Contamination. Our pipeline and distribution operations have in the past employed elemental mercury in measuring and regulating equipment. It is possible that small amounts of mercury may have been spilled in the course of normal maintenance and replacement operations and that these spills may have contaminated the immediate area with elemental mercury. We have found this type of contamination at some sites in the past, and we have conducted remediation at these sites. It is possible that other contaminated sites may exist and that remediation costs may be incurred for these sites. Although the total amount of these costs is not 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.

Asbestos. Some facilities formerly owned by our predecessors have contained asbestos insulation and other asbestos-containing materials. We or our predecessor companies have been named, along with numerous others, as a defendant in lawsuits filed by certain individuals who claim injury due to exposure to asbestos during work at such formerly owned facilities. We anticipate that additional claims like those received may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, we intend to continue vigorously contesting claims that we do not consider to have merit and do not expect, based on our experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on 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. In addition, we have been named from time to time as a defendant in litigation related to such sites. Although the ultimate outcome of such matters cannot be predicted at this time, we do not expect, based on our experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on our financial condition, results of operations or cash flows.

EMPLOYEES

As of December 31, 2007, we had 4,609 full-time employees. The following table sets forth the number of our employees by business segment:

Business Segment	Number	Number Represented by Unions or Other Collective Bargaining Groups
Natural Gas Distribution	3,685	1,412
Competitive Natural Gas Sales and Services	117	—
Interstate Pipelines	611	—
Field Services	196	—
Total	4,609	1,412

As of December 31, 2007, approximately 31% of our employees are subject to collective bargaining agreements. We have four collective bargaining agreements, (1) United Steel Workers (USW) Local 13-227, (2) Office and Professional Employees International Union (OPEIU) Local 12 Metro, (3) OPEIU Local 12 Mankato, and (4) USW

Local 13-1, that are scheduled to expire in 2008 that collectively cover approximately 16% of our employees. We have a good relationship with these bargaining units and expect to renegotiate new agreements in 2008.

Item 1A. *Risk Factors*

The following, along with any additional legal proceedings identified or incorporated by reference in Item 3 of this report, summarizes the principal risk factors associated with our business.

Risk Factors Affecting Our Businesses

Rate regulation of our business may delay or deny our ability to earn a reasonable return and fully recover our costs.

Rates for Gas Operations are regulated by certain municipalities and state commissions, and the rates of our interstate pipelines are regulated by the FERC, based on an analysis of our invested capital and our expenses in a test year. Thus, the rates that we are allowed to charge may not match our expenses at any given time. The regulatory process in which rates are determined may not always result in rates that will produce full recovery of our costs and enable us to earn a reasonable return on our invested capital.

Our businesses must compete with alternative energy sources, which could result in our marketing less natural gas, and our interstate pipelines and field services businesses must compete directly with others in the transportation, storage, gathering, treating and processing of natural gas, which could lead to lower prices, either of which could have an adverse impact on our results of operations, financial condition and cash flows.

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. We 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 and competitive natural gas sales and services businesses are subject to fluctuations in natural gas pricing levels, which could affect the ability of our suppliers and customers to meet their obligations or otherwise adversely affect our liquidity.

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

If we were to fail to renegotiate a contract with one of our significant pipeline customers or if we renegotiate the contract on less favorable terms, there could be an adverse impact on our operations.

Since October 31, 2006, our contract with Laclede, one of our pipeline customers, has been terminable upon one year’s prior notice. We have not received a termination notice and are currently negotiating a long-term contract with Laclede. If Laclede were to terminate this contract or if we were to renegotiate this contract at rates substantially lower than the rates provided in the current contract, there could be an adverse effect on our results of operations, financial condition and cash flows.

A decline in our credit rating could result in us having to provide collateral in order to purchase gas.

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

The revenues and results of operations of our interstate pipelines and field services businesses are subject to fluctuations in the supply of natural gas.

Our interstate pipelines and field services businesses largely rely on natural gas sourced in the various supply basins located in the Mid-continent 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 is 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.

The actual cost of pipelines under construction and related compression facilities may be significantly higher than our current estimates.

Our subsidiaries are involved in significant pipeline construction projects. The construction of new pipelines and related compression facilities requires the expenditure of significant amounts of capital, which may exceed our estimates. These projects may not be completed at the budgeted cost, on schedule or at all. The construction of new pipeline or compression facilities is subject to construction cost overruns due to labor costs, costs of equipment and materials such as steel and nickel, labor shortages or delays, weather delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. As a result, there is the risk that the new facilities may not be able to achieve our expected investment return, which could adversely affect our financial condition, results of operations or cash flows.

The states in which we provide regulated local gas distribution may, either through legislation or rules, adopt restrictions similar to or broader than those under the Public Utility Holding Company Act of 1935 regarding organization, financing and affiliate transactions that could have significant adverse impacts on our ability to operate.

The Public Utility Holding Company Act of 1935, to which CenterPoint Energy was subject prior to its repeal in the Energy Act, provided a comprehensive regulatory structure governing the organization, capital structure, intracompany relationships and lines of business that could be pursued by registered holding companies and their member companies. Following repeal of that Act, some states in which we do business have sought to expand their own regulatory frameworks to give their regulatory authorities increased jurisdiction and scrutiny over similar aspects of the utilities that operate in their states. Some of these frameworks attempt to regulate financing activities, acquisitions and divestitures, and arrangements between the utilities and their affiliates, and to restrict the level of non-utility businesses that can be conducted within the holding company structure. Additionally they may impose record keeping, record access, employee training and reporting requirements related to affiliate transactions and reporting in the event of certain downgrading of the utility’s bond rating.

These regulatory frameworks could have adverse effects on our ability to operate our utility operations, to finance our business and to provide cost-effective utility service. In addition, if more than one state adopts restrictions over similar activities, it may be difficult for us to comply with competing regulatory requirements.

Risk Factors Associated with Our Consolidated Financial Condition

If we are unable to arrange future financings on acceptable terms, our ability to refinance existing indebtedness could be limited.

As of December 31, 2007, we had $3.0 billion of outstanding long-term indebtedness on a consolidated basis. As of December 31, 2007, approximately $319 million principal amount of this debt must be paid through 2010. Our future financing activities 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 market in which we operate;
- maintenance of acceptable credit ratings;
- market expectations regarding our future earnings and probable cash flows;
- market perceptions of our and CenterPoint Energy's ability to access capital markets on reasonable terms; and
- provisions of relevant tax and securities laws.

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

The financial condition and liquidity of our parent company could affect our access to capital, our credit standing and our financial condition.

Our ratings and credit may be impacted by CenterPoint Energy's credit standing. As of December 31, 2007, CenterPoint Energy and its subsidiaries other than us have approximately $523 million principal amount of debt required to be paid through 2010. This amount excludes amounts related to capital leases, transition bonds and indexed debt securities obligations, but includes $123 million of 3.75% convertible notes converted by holders in January and February 2008. In addition, CenterPoint Energy has cash settlement obligations with respect to $412 million of outstanding 3.75% convertible notes on which holders could exercise their conversion rights during the first quarter of 2008 and in subsequent quarters in which CenterPoint Energy's common stock price causes such notes to be convertible. We cannot assure you that CenterPoint Energy and its other subsidiaries will be able to pay or refinance these amounts. If CenterPoint Energy were to experience a deterioration in its credit standing or liquidity difficulties, our access to credit and our credit ratings could be adversely affected.

We are an indirect wholly owned subsidiary of CenterPoint Energy. CenterPoint Energy can exercise substantial control over our dividend policy and business and operations and could do so in a manner that is adverse to our interests.

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

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

There are no contractual restrictions on our ability to pay dividends to CenterPoint Energy. Our management could decide to increase our dividends to CenterPoint Energy to support its cash needs. This could adversely affect our liquidity. However, under our credit facility and our receivables facility, our ability to pay dividends is restricted by a covenant that debt as a percentage of total capitalization may not exceed 65%.

The use of derivative contracts by us and our subsidiaries in the normal course of business could result in financial losses that negatively impact our results of operations and those of our subsidiaries.

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

We derive a substantial portion of our operating income from subsidiaries through which we hold a substantial portion of our assets.

We derive a substantial portion of our operating income from, and hold a substantial portion of our assets through, our subsidiaries. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide us with funds for our payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit our subsidiaries' ability to make payments or other distributions to us, and our subsidiaries could agree to contractual restrictions on their ability to make distributions.

Our right to receive any assets of any subsidiary, and therefore the right of our creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if we were a creditor of any subsidiary, our rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by us.

Other Risks

We are subject to operational and financial risks and liabilities arising from environmental laws and regulations.

Our operations are subject to stringent and complex laws and regulations pertaining to health, safety and the environment, as discussed in "Business — Environmental Matters" in Item 1 of this report. As an owner or operator of natural gas pipelines and distribution systems, and gas gathering and processing systems, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;

- requiring remedial action to mitigate pollution conditions caused by our operations, or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

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

- construct or acquire new equipment;
- acquire permits for facility operations;
- modify or replace existing and proposed equipment; and
- clean up or decommission waste disposal areas, fuel storage and management facilities and other locations and facilities.

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

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. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of our facilities may not be sufficient to restore the loss or damage without negative impact on our results of operations, financial condition and cash flows.

We and CenterPoint Energy could incur liabilities associated with businesses and assets that we have transferred to others.

In connection with the organization and capitalization of Reliant Resources, Inc. (RRI), RRI and its subsidiaries assumed liabilities associated with various assets and businesses Reliant Energy, Incorporated (Reliant Energy) transferred to them. RRI also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, CenterPoint Energy and its subsidiaries, including us, with respect to liabilities associated with the transferred assets and businesses. These indemnity provisions were intended to place sole financial responsibility on RRI and its subsidiaries for all liabilities associated with the current and historical businesses and operations of RRI, regardless of the time those liabilities arose. If RRI were unable to satisfy a liability that has been so assumed in circumstances in which Reliant Energy and its subsidiaries were not released from the liability in connection with the transfer, we and CenterPoint Energy could be responsible for satisfying the liability.

Prior to CenterPoint Energy's distribution of its ownership in RRI to its shareholders, we had guaranteed certain contractual obligations of what became RRI's trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure us against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for our benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In February 2007, we and CenterPoint

Energy made a formal demand on RRI in connection with one of the two remaining guaranties under procedures provided by the Master Separation Agreement, dated December 31, 2000, between Reliant Energy and RRI. That demand sought to resolve a disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. In December 2007, we, CenterPoint Energy and RRI amended the agreement relating to the security to be provided by RRI for these guaranties, pursuant to which we released the $29.3 million in letters of credit RRI had provided as security, and RRI agreed to provide cash or new letters of credit to secure us against exposure under the remaining guaranties as calculated under the new agreement if and to the extent changes in market conditions exposed us to a risk of loss on those guaranties.

Our remaining exposure under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under those transportation contracts, which will be effective until 2018, was approximately $135 million as of December 31, 2007. RRI continues to meet its obligations under the contracts, and we believe current market conditions make those contracts valuable in the near term and that additional security is not needed at this time. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the contracts or if RRI should fail to provide security in the event market conditions change adversely, our exposure to the counterparty under the guaranty could exceed the security provided by RRI.

RRI's unsecured debt ratings are currently below investment grade. If RRI were unable to meet its obligations, it would need to consider, among various options, restructuring under the bankruptcy laws, in which event RRI might not honor its indemnification obligations and claims by RRI's creditors might be made against us as its former owner.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

Character of Ownership

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

Natural Gas Distribution

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

Competitive Natural Gas Sales and Services

For information regarding the properties of our Competitive Natural Gas Sales and Services business segment, please read "Business — Competitive Natural Gas Sales and Services — Assets" in Item 1 of this report, which information is incorporated herein by reference.

Interstate Pipelines

For information regarding the properties of our Interstate Pipelines business segment, please read "Business —Interstate Pipelines — Assets" in Item 1 of this report, which information is incorporated herein by reference.

Field Services

For information regarding the properties of our Field Services business segment, please read "Business — Field Services — Assets" in Item 1 of this report, which information is incorporated herein by reference.

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Item 3. ***Legal Proceedings***

For a discussion of material legal and regulatory proceedings affecting us, please read "Business — Regulation" and "Business — Environmental Matters" in Item 1 of this report and Notes 3 and 8(d) to our consolidated financial statements, which information is incorporated herein by reference.

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

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

PART II

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

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

In each of 2006 and 2007, we paid dividends on our common stock of $100 million to Utility Holding, LLC.

Our revolving credit facility limits our debt as a percentage of total capitalization to 65%. This covenant could restrict our ability to distribute dividends.

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). The ratio of earnings to fixed charges as calculated pursuant to Securities and Exchange Commission rules was 1.99, 2.20, 2.64, 2.67 and 3.10 for the years ended December 31, 2003, 2004, 2005, 2006 and 2007, respectively.

Item 7. ***Management's Narrative Analysis of Results of Operations***

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

Background

We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy). We own and operate natural gas distribution systems in six states. Our subsidiaries own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of ours offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

Business Segments

Because we are an indirect wholly owned subsidiary of CenterPoint Energy, our determination of reportable segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. In this section, we discuss our results on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. The results of our business operations are significantly impacted by weather, customer growth, cost management, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to which we are subject. Our natural gas distribution services and interstate pipelines are subject to rate regulation. A summary of our reportable business segments as of December 31, 2007 is set forth below:

Natural Gas Distribution

We own and operate our regulated natural gas distribution business, which engages in intrastate natural gas sales to, and natural gas transportation for, approximately 3.2 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas.

Competitive Natural Gas Sales and Services

Our operations also include non-rate regulated retail and wholesale natural gas sales to, and transportation services for, commercial and industrial customers in the six states listed above as well as several other Midwestern and Eastern states.

Interstate Pipelines

Our interstate pipelines business owns and operates approximately 8,100 miles of gas transmission lines primarily located in Arkansas, Louisiana, Missouri, Oklahoma and Texas. This business also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.2 billion cubic feet (Bcf) per day and a combined working gas capacity of approximately 59.0 Bcf. Most storage operations are in north Louisiana and Oklahoma. This business has recently completed the first two phases of its Carthage to Perryville pipeline in 2007 adding over 1.2 Bcf per day, and is in the process of completing its third phase. In addition, construction has begun on the Southeast Supply Header (SESH) pipeline joint venture project.

Field Services

Our field services business owns and operates approximately 3,500 miles of gathering pipelines and processing plants that collect, treat and process natural gas from approximately 151 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Other Operations

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

EXECUTIVE SUMMARY

Significant Events in 2007 and 2008

Debt Financing Transactions

In February 2007, we issued $150 million aggregate principal amount of senior notes due in February 2037 with an interest rate of 6.25%. The proceeds from the sale of the senior notes were used to repay advances for the purchase of receivables under our $375 million receivables facility. Such repayment provides increased liquidity and capital resources for our general corporate purposes.

In June 2007, we entered into an amended and restated bank credit facility. Our amended credit facility is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility's first drawn cost remains at the London Interbank Offered Rate (LIBOR) plus 45 basis points based on our current credit ratings.

In October 2007, we issued $250 million aggregate principal amount of 6.125% senior notes due in November 2017 and $250 million aggregate principal amount of 6.625% senior notes due in November 2037. The proceeds from the sale of the senior notes were used for general corporate purposes, including repayment or refinancing of debt, including $300 million of our 6.5% senior notes due February 1, 2008, capital expenditures, working capital and loans to or investments in affiliates. Pending application of the proceeds for these purposes, we repaid borrowings under our revolving credit and receivables facilities.

In October 2007, we amended our receivables facility and extended the termination date to October 28, 2008. The facility size will range from $150 million to $375 million during the period from October 2007 to the October 28, 2008 termination date. The variable size of the facility was designed to track the seasonal pattern of receivables in our natural gas businesses.

Interstate Pipeline Expansion

Carthage to Perryville. In April 2007, CenterPoint Energy Gas Transmission (CEGT), our wholly owned subsidiary, completed phase one construction of a 172-mile, 42-inch diameter pipeline and related compression facilities for the transportation of gas from Carthage, Texas to CEGT's Perryville hub in northeast Louisiana. On May 1, 2007, CEGT began service under its firm transportation agreements with shippers of approximately 960 million cubic feet (MMcf) per day. CEGT's second phase of the project, which involved adding compression that increased the total capacity of the pipeline to approximately 1.25 Bcf per day, was placed into service in August 2007. CEGT has signed firm contracts for the full capacity of phases one and two.

In May 2007, CEGT received Federal Energy Regulatory Commission (FERC) approval for the third phase of the project to expand capacity of the pipeline to 1.5 Bcf per day by adding additional compression and operating at higher pressures, and in July 2007, CEGT received approval from the Pipeline and Hazardous Materials Administration (PHMSA) to increase the maximum allowable operating pressure. The PHMSA's approval contained certain conditions and requirements, which CEGT expects to satisfy in the first quarter of 2008. CEGT has executed contracts for approximately 150 MMcf per day of the 250 MMcf per day phase three expansion. The third phase is projected to be in-service in the second quarter of 2008.

SESH. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., our wholly owned subsidiary, and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture, SESH, to construct, own and operate a 270-mile pipeline with a capacity of approximately 1 Bcf per day that will extend from CEGT's Perryville hub in northeast Louisiana to an interconnection in southern Alabama with Gulfstream Natural Gas System, which is 50% owned by an affiliate of Spectra. We account for our 50% interest in SESH as an equity investment. In 2006, SESH signed agreements with shippers for firm transportation services, which subscribed capacity of 945 million cubic feet per day. Additionally, SESH and Southern Natural Gas (SNG) have executed a definitive agreement that provides for SNG to jointly own the first 115 miles of the pipeline. Under the agreement, SNG will own an undivided interest in the portion of the pipeline from Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter was increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that will increase the jointly owned capacity up to 500 MMcf per day, subject to FERC approval.

An application to construct, own and operate the pipeline was filed with the FERC in December 2006. In September 2007, the FERC issued the certificate authorizing the construction of the pipeline. This FERC approval does not include the expansion capacity that would take SNG to 500 MMcf per day. SESH began construction in November 2007. SESH expects to complete construction of the pipeline as approved by the FERC in the second half of 2008. SESH's net costs after SNG's contribution are estimated to have increased to approximately $1 billion.

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, including deregulation, re-regulation, environmental regulations, including regulations related to global climate change, and changes in or application of laws or regulations applicable to the various aspects of our business;
- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;

- cost overruns on major capital projects that cannot be recouped in prices;
- 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;
- the timing and extent of changes in the supply of natural gas;
- the timing and extent of changes in natural gas basis differentials;
- weather variations and other natural phenomena;
- changes in interest rates or rates of inflation;
- commercial bank and financial market conditions, our access to capital, the cost of such capital, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;
- actions by rating agencies;
- effectiveness of our risk management activities;
- inability of various counterparties to meet their obligations to us;
- the ability of Reliant Energy, Inc. (RRI) to satisfy its obligations to us in connection with the contractual arrangements pursuant to which we are their guarantor;
- the outcome of litigation brought by or against us;
- our ability to control costs;
- the investment performance of CenterPoint Energy's employee benefit plans;
- our potential business strategies, including acquisitions or dispositions of assets or businesses, which we cannot assure will be completed or will have the anticipated benefits to us; and
- other factors we discuss under "Risk Factors" in Item 1A of this report and in other reports we file from time to time with the Securities and Exchange Commission.

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 as well as natural gas basis differentials. 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 (in millions) for the years ended December 31, 2005, 2006 and 2007, followed by a discussion of our consolidated results of operations based on operating income. We have provided a reconciliation of consolidated operating income to net income below.

	Year Ended December 31,		
	2005	2006	2007
Revenues	$ 8,070	$ 7,528	$ 7,776
Expenses:			
Natural gas	6,509	5,909	5,995
Operation and maintenance	743	798	800
Depreciation and amortization	198	200	215
Taxes other than income taxes	156	149	140
Total	7,606	7,056	7,150
Operating Income	464	472	626
Interest and other finance charges	(176)	(167)	(187)
Other income, net	21	18	21
Income Before Income Taxes	309	323	460
Income Tax Expense	(116)	(116)	(173)
Net Income	$ 193	$ 207	$ 287

2007 Compared to 2006. We reported net income of $287 million for 2007 as compared to $207 million for 2006. The increase in net income of $80 million was primarily due to a $94 million increase in operating income from our Natural Gas Distribution business segment, a $56 million increase in operating income from our Interstate Pipelines business segment and a $10 million increase in operating income from our Field Services business segment, partially offset by a $57 million increase in income tax expense due to higher earnings and a $20 million increase in interest expense.

Our effective tax rate for 2007 and 2006 was 37.6% and 36.1%, respectively.

2006 Compared to 2005. We reported net income of $207 million for 2006 as compared to $193 million for 2005. The increase in net income of $14 million was primarily due to a $19 million increase in operating income from our Field Services business segment, a $17 million increase in operating income from our Competitive Natural Gas Sales and Services business segment, a $16 million increase in operating income from our Interstate Pipelines business segment and a decrease in interest expense of $9 million, partially offset by a decrease in operating income from our Natural Gas Distribution business segment of $51 million.

Our effective tax rate for 2006 and 2005 was 36.1% and 37.4%, respectively.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for 2005, 2006 and 2007. Included in revenues are inter-segment sales. We account for inter-segment sales as if the sales were to third parties, that is, at current market prices.

Operating Income (Loss) by Business Segment

	Year Ended December 31,		
	2005	2006	2007
Natural Gas Distribution	$ 175	$ 124	$ 218
Competitive Natural Gas Sales and Services	60	77	75
Interstate Pipelines	165	181	237
Field Services	70	89	99
Other Operations	(6)	1	(3)
Total Consolidated Operating Income	$ 464	$ 472	$ 626

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2005, 2006 and 2007 (in millions, except throughput and customer data):

	Year Ended December 31, 2005	2006	2007
Revenues	$ 3,846	$ 3,593	$ 3,759
Expenses:			
Natural gas	2,841	2,598	2,683
Operation and maintenance	551	594	579
Depreciation and amortization	152	152	155
Taxes other than income taxes	127	125	124
Total expenses	3,671	3,469	3,541
Operating Income	$ 175	$ 124	$ 218
Throughput (in Bcf):			
Residential	160	152	172
Commercial and industrial	215	224	232
Total Throughput	375	376	404
Average number of customers:			
Residential	2,839,947	2,883,927	2,931,523
Commercial and industrial	244,782	243,265	246,993
Total	3,084,729	3,127,192	3,178,516

2007 Compared to 2006. Our Natural Gas Distribution business segment reported operating income of $218 million for 2007 as compared to $124 million for 2006. Operating income improved as a result of increased usage primarily due to a return to more normal weather in 2007 compared to the unusually mild weather in 2006 ($33 million), growth from the addition of over 38,000 customers in 2007 ($9 million), the effect of the 2006 purchased gas cost write-off described below ($21 million), the effect of rate changes ($7 million) and reduced operation and maintenance expenses ($15 million). Operation and maintenance expenses declined primarily as a result of costs associated with staff reductions incurred in 2006 ($17 million) and settlement of certain rate case-related items ($9 million), partially offset by increases in bad debts and collection costs ($8 million) and other services ($5 million).

2006 Compared to 2005. Our Natural Gas Distribution business segment reported operating income of $124 million for 2006 as compared to $175 million for 2005. Decreases in operating margins (revenues less natural gas costs) include a $21 million write-off in 2006 of purchased gas costs for periods prior to July 2004, the recovery of which was denied by the Minnesota Public Utilities Commission, and the impact of milder weather and decreased usage ($30 million). These decreases were partially offset by higher margins from rate and service charge increases and rate design changes ($35 million), along with the addition of over 42,000 customers in 2006 ($9 million). Operation and maintenance expenses increased primarily as a result of costs associated with staff reductions ($17 million), benefit costs increases ($6 million), higher costs of goods and services ($8 million) and higher bad debt expenses ($10 million), partially offset by higher litigation reserves recorded in 2005 ($11 million).

During the third quarter of 2005, our east Texas, Louisiana and Mississippi natural gas service areas were affected by Hurricanes Katrina and Rita. Damage to our facilities was limited, but approximately 10,000 homes and businesses were damaged to such an extent that they were not able to, and in some cases continue to be unable to, take service. The impact on the Natural Gas Distribution business segment's operating income was not material.

Competitive Natural Gas Sales and Services

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for 2005, 2006 and 2007 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2005	2006	2007
Revenues	$ 4,129	$ 3,651	$ 3,579
Expenses:			
Natural gas	4,033	3,540	3,467
Operation and maintenance	30	30	31
Depreciation and amortization	2	1	5
Taxes other than income taxes	4	3	1
Total expenses	4,069	3,574	3,504
Operating Income	$ 60	$ 77	$ 75
Throughput (in Bcf):			
Wholesale — third parties	304	335	314
Wholesale — affiliates	27	36	9
Retail	156	149	192
Pipeline	51	35	7
Total Throughput	538	555	522
Average number of customers:			
Wholesale	138	140	235
Retail	6,328	6,452	6,789
Pipeline	142	138	12
Total	6,608	6,730	7,036

2007 Compared to 2006. Our Competitive Natural Gas Sales and Services business segment reported operating income of $75 million for 2007 compared to $77 million for 2006. The decrease in operating income of $2 million was primarily due to reduced opportunities for optimization of pipeline and storage assets resulting from lower locational and seasonal natural gas price differentials in the wholesale business ($10 million) offset by an increase in sales to commercial and industrial customers in the retail business ($3 million). In addition, 2007 included a charge to income from mark-to-market accounting for non-trading derivatives ($10 million) and a write-down of natural gas inventory to the lower of average cost or market ($11 million), compared to a gain from mark-to-market accounting ($37 million) and an inventory write-down ($66 million) for 2006.

2006 Compared to 2005. Our Competitive Natural Gas Sales and Services business segment reported operating income of $77 million for 2006 as compared to $60 million for 2005. The increase in operating income of $17 million was primarily driven by improved operating margins (revenues less natural gas costs) resulting from seasonal price differentials and favorable basis differentials over the pipeline capacity that we control ($44 million) and a favorable change in unrealized gains resulting from mark-to-market accounting ($37 million), partially offset by write-downs of natural gas inventory to the lower of average cost or market ($66 million).

Interstate Pipelines

The following table provides summary data of our Interstate Pipelines business segment for 2005, 2006 and 2007 (in millions, except throughput data):

	Year Ended December 31,		
	2005	2006	2007
Revenues	$ 386	$ 388	$ 500
Expenses:			
Natural gas	47	31	83
Operation and maintenance	121	120	125
Depreciation and amortization	36	37	44
Taxes other than income taxes	17	19	11
Total expenses	221	207	263
Operating Income	$ 165	$ 181	$ 237
Throughput (in Bcf):			
Transportation	914	939	1,216
Other	2	1	5
Total Throughput	916	940	1,221

2007 Compared to 2006. Our Interstate Pipeline business segment reported operating income of $237 million for 2007 compared to $181 million for 2006. The increase in operating income of $56 million was driven primarily by the new Carthage to Perryville pipeline ($42 million), other transportation and ancillary services ($20 million), lower spending in 2007 on project development costs ($6 million) and a decrease in other taxes ($8 million) related to the settlement of certain state tax issues. These favorable variances to operating income were partially offset by lower sales in 2007 of excess gas associated with storage enhancement projects ($15 million) and increased operating expenses ($6 million).

2006 Compared to 2005. Our Interstate Pipelines business segment reported operating income of $181 million for 2006 as compared to $165 million for 2005. Operating margins (natural gas sales less gas cost) increased by $18 million. This increase was driven primarily by increased demand for transportation services and ancillary services ($15 million). Operation and maintenance expenses decreased by $1 million primarily due to the gain on sale of excess gas during 2006 ($18 million) combined with lower litigation reserves ($6 million) in 2006 compared to 2005. These favorable variances were partially offset by a write-off of project development expenses associated with the Mid-Continent Crossing pipeline project which was discontinued in 2006 ($11 million) as well as increased operating expenses ($11 million) largely associated with staffing increases and costs associated with continued compliance with pipeline integrity regulations.

Field Services

The following table provides summary data of our Field Services business segment for 2005, 2006 and 2007 (in millions, except throughput data):

	Year Ended December 31,		
	2005	2006	2007
Revenues	$ 120	$ 150	$ 175
Expenses:			
Natural gas	(10)	(10)	(4)
Operation and maintenance	49	59	66
Depreciation and amortization	9	10	11
Taxes other than income taxes	2	2	3
Total expenses	50	61	76
Operating Income	$ 70	$ 89	$ 99
Throughput (in Bcf):			
Gathering	353	375	398

2007 Compared to 2006. Our Field Services business segment reported operating income of $99 million for 2007 compared to $89 million for 2006. Continued increased demand for gas gathering and ancillary services ($27 million) was partially offset by lower commodity prices ($10 million) and increased operation and maintenance expenses related to cost increases and expanded operations ($7 million).

2006 Compared to 2005. Our Field Services business segment reported operating income of $89 million for 2006 as compared to $70 million for 2005. The increase of $19 million was driven by increased gas gathering and ancillary services, which reflects contributions from new facilities placed in service ($27 million) and higher commodity prices ($3 million), partially offset by higher operation and maintenance expenses ($10 million).

In addition, this business segment recorded equity income of $6 million, $6 million and $10 million for the years ended December 31, 2005, 2006 and 2007, respectively, from its 50% interest in the Waskom Joint Venture. These amounts are included in Other — net under the Other Income (Expense) caption.

Fluctuations in Commodity Prices and Derivative Instruments

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

LIQUIDITY

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, investments in and advances to SESH, debt service requirements, and working capital needs. Our principal cash requirements for 2008 include approximately $590 million of capital expenditures, maturing long-term debt aggregating approximately $307 million and investment in and advances to SESH of approximately $294 million.

We expect that borrowings under our credit facilities and anticipated cash flows from operations will be sufficient to meet our cash needs in 2008. Cash needs or discretionary financing or refinancing may also result in the issuance of debt securities in the capital markets.

The following table sets forth our capital expenditures for 2007 and estimates of our capital requirements for 2008 through 2012 (in millions):

	2007	2008	2009	2010	2011	2012
Natural Gas Distribution	$ 191	$ 209	$ 192	$ 193	$ 196	$ 203
Competitive Natural Gas Sales and Services	7	18	2	2	2	2
Interstate Pipelines	308	209	133	77	72	76
Field Services	74	154	83	93	94	85
Total	$ 580	$ 590	$ 410	$ 365	$ 364	$ 366

The following table sets forth estimates of our contractual obligations, including payments due by period (in millions):

Contractual Obligations	Total	2008	2009-2010	2011-2012	2013 and thereafter
Long-term debt	$ 2,952	$ 307	$ 12	$ 738	$ 1,895
Interest payments — long-term debt(1)	1,696	195	369	297	835
Short-term borrowings	232	232	—	—	—
Operating leases(2)	64	15	22	13	14
Benefit obligations(3)	—	—	—	—	—
Purchase obligations(4)	27	27	—	—	—
Non-trading derivative liabilities	74	60	14	—	—
Other commodity commitments(5)	3,027	743	563	550	1,171
Joint venture obligations(6)	294	294	—	—	—
Income taxes(7)	—	—	—	—	—
Total contractual cash obligations	$ 8,366	$ 1,873	$ 980	$ 1,598	$ 3,915

(1) We calculated estimated interest payments for long-term debt as follows: for fixed-rate debt and term debt, we calculated interest based on the applicable rates and payment dates; for variable-rate debt and/or non-term debt, we used interest rates in place as of December 31, 2007. We typically expect to settle such interest payments with cash flows from operations and short-term borrowings.

(2) For a discussion of operating leases, please read Note 8(b) to our consolidated financial statements.

(3) We expect to contribute approximately $14 million to our postretirement benefits plan in 2008 to fund a portion of our obligations in accordance with rate orders or to fund pay-as-you-go costs associated with the plan.

(4) Represents capital commitments for material in connection with the construction of a new pipeline by our Interstate Pipelines business segment. This project has been included in the table of capital expenditures presented above.

(5) For a discussion of other commodity commitments, please read Note 8(a) to our consolidated financial statements.

(6) We anticipate SESH to be in-service mid-year 2008 and ultimately will be funded with approximately 50% debt.

(7) As of December 31, 2007, the Company had a receivable for uncertain tax positions of $11 million.

Arkansas Public Service Commission (APSC), Affiliate Transaction Rulemaking Proceeding. In December 2006, the APSC adopted new rules governing affiliate transactions involving public utilities operating in Arkansas. In February 2007, in response to requests by us and other gas and electric utilities operating in Arkansas, the APSC granted reconsideration of the rules and stayed their operation in order to permit additional consideration. In May 2007, the APSC adopted revised rules, which incorporated many revisions proposed by the utilities, the Arkansas Attorney General and the APSC staff. The revised rules prohibit affiliated financing transactions for purposes not related to utility operations, but permit the continuation of existing money pool and multi-jurisdictional financing arrangements such as those we currently have in place. Non-financial affiliate transactions generally have to be priced under an asymmetrical pricing formula under which utilities would receive the better of cost or market pricing for goods and services provided to or from the utility operations. However, corporate services provided at fully-allocated cost such as those provided by service companies are exempt. The rules also restrict utilities from engaging in businesses other than utility and utility-related businesses if the total book value of non-utility businesses exceeds 10% of the book value of the utility and its affiliates. However, existing businesses are grandfathered under the revised rules. The revised rules also permit utilities to petition for waivers of financing and non-financial rules that would otherwise be applicable to their transactions.

The APSC's revised rules impose record keeping, record access, employee training and reporting requirements related to affiliate transactions, including notification to the APSC of the formation of new affiliates that will engage in transactions with the utility and annual certification by the utility's president or chief executive officer and its chief financial officer of compliance with the rules. In addition, the revised rules require a report to the APSC in the event the utility's bond rating is downgraded in certain circumstances. Although the revised rules impose new requirements on our operations in Arkansas, at this time we do not anticipate that the revised rules will have an adverse effect on existing operations in Arkansas. In September 2007, Gas Operations made a filing with the APSC in accordance with the revised rules to document existing practices that would be covered by grandfathering provisions of those rules.

Off-Balance Sheet Arrangements. Other than operating leases and the guaranties described below, we have no off-balance sheet arrangements.

Prior to CenterPoint Energy's distribution of its ownership in RRI to its shareholders, we had guaranteed certain contractual obligations of what became RRI's trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure us against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for our benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In February 2007, we and CenterPoint Energy made a formal demand on RRI in connection with one of the two remaining guaranties under procedures provided by the Master Separation Agreement, dated December 31, 2000, between Reliant Energy, Incorporated and RRI. That demand sought to resolve a disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. In December 2007, we, CenterPoint Energy and RRI amended the agreement relating to the security to be provided by RRI for these guaranties, pursuant to which we released the $29.3 million in letters of credit RRI had provided as security, and RRI agreed to provide cash or new letters of credit to secure us against exposure under the remaining guaranties as calculated under the new agreement if and to the extent changes in market conditions exposed us to a risk of loss on those guaranties.

Our remaining exposure under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under those transportation contracts, which will be effective until 2018, was approximately $135 million as of December 31, 2007. RRI continues to meet its obligations under the contracts, and we believe current market conditions make those contracts valuable in the near term and that additional security is not needed at this time. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the contracts or if RRI should fail to provide security in the event market conditions change adversely, our exposure to the counterparty under the guaranty could exceed the security provided by RRI.

Senior Notes. In February 2007, we issued $150 million aggregate principal amount of senior notes due in February 2037 with an interest rate of 6.25%. The proceeds from the sale of the senior notes were used to repay advances for the purchase of receivables under our receivables facility. Such repayment provided increased liquidity and capital resources for our general corporate purposes.

In October 2007, we issued $250 million aggregate principal amount of 6.125% senior notes due in November 2017 and $250 million aggregate principal amount of 6.625% senior notes due in November 2037. The proceeds from the sale of the senior notes were used for general corporate purposes, including repayment or refinancing of debt, including $300 million of our 6.5% senior notes due February 1, 2008, capital expenditures, working capital and loans to or investments in affiliates. Pending application of the proceeds for these purposes, we repaid borrowings under our revolving credit and receivables facilities.

Credit and Receivables Facilities. In June 2007, we entered into an amended and restated bank credit facility. Our amended credit facility is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility’s first drawn cost remains at LIBOR plus 45 basis points based on our current credit ratings. The facility contains covenants, including a debt to total capitalization covenant.

Under the credit facility, an additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on our credit rating. Borrowings under each of the facilities are subject to customary terms and conditions. However, there is no requirement that we make representations prior to borrowings as to the absence of material adverse changes or litigation that could be expected to have a material adverse effect. Borrowings under the credit facility are subject to acceleration upon the occurrence of events of default that we consider customary.

Our receivables facility terminates in October 2008. The facility size will range from $150 million to $375 million during the period from December 31, 2007 to the October 28, 2008 termination date of the facility. At December 31, 2007, $232 million was utilized under the facility.

We are currently in compliance with the various business and financial covenants contained in the respective receivables and credit facility.

As of February 15, 2008, we had the following facilities (in millions):

Date Executed	Company	Type of Facility	Size of Facility	Amount Utilized at February 15, 2008	Termination Date
June 29, 2007	CERC Corp.	Revolver	$ 950	$ 87 (1)	June 29, 2012
October 30, 2007	CERC	Receivables	375	85	October 28, 2008

(1) Includes $74 million of borrowings under the credit facility and $13 million of outstanding letters of credit.

Our $950 million credit facility backstops a $950 million commercial paper program under which we began issuing commercial paper in February 2008. Our commercial paper is rated “P-3” by Moody’s, “A-2” by S&P, and “F2” by Fitch. As a result of the credit ratings on our commercial paper program, we do not expect to be able to rely on the sale of commercial paper to fund all of our short-term borrowing requirements. We cannot assure you that these ratings, or the credit ratings set forth below in “— Impact on Liquidity of a Downgrade in 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 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 and the execution of our commercial strategies.

Securities Registered with the SEC. At December 31, 2007, we had a shelf registration statement covering $400 million principal amount of debt securities.

Temporary Investments. As of February 15, 2008, we had no external temporary investments.

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 net funding requirements of the money pool are expected to be met with borrowings under CenterPoint Energy’s revolving credit facility or the sale of CenterPoint Energy’s commercial paper. At February 15, 2008, we had borrowings from the money pool aggregating $188 million. The money pool may not provide sufficient funds to meet our cash needs.

Impact on Liquidity of a Downgrade in Credit Ratings. As of February 15, 2008, 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)
Baa3	Stable	BBB	Positive	BBB	Stable

(1) A “stable” outlook from Moody’s indicates that Moody’s does not expect to put the rating on review for an upgrade or downgrade within 18 months from when the outlook was assigned or last affirmed.

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

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

A decline in credit ratings could increase borrowing costs under our $950 million 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 could negatively impact our ability to complete capital market transactions. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments.

CenterPoint Energy Services, Inc. (CES), our wholly owned subsidiary operating in our Competitive Natural Gas Sales and Services business segment, provides comprehensive natural gas sales and services primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. In order to economically hedge its exposure to natural gas prices, CES uses derivatives with provisions standard for the industry, including those pertaining to credit thresholds. Typically, the credit threshold negotiated with each counterparty defines the amount of unsecured credit that such counterparty will extend to CES. To the extent that the credit exposure that a counterparty has to CES at a particular time does not exceed that credit threshold, CES is not obligated to provide collateral. Mark-to-market exposure in excess of the credit threshold is routinely collateralized by CES. As of December 31, 2007, the amount posted as collateral amounted to approximately $47 million. Should the credit ratings of CERC Corp. (as the credit support provider for CES) fall below certain levels, CES would be required to provide additional collateral on two business days' notice up to the amount of its previously unsecured credit limit. We estimate that as of December 31, 2007, unsecured credit limits extended to CES by counterparties aggregate $154 million; however, utilized credit capacity is significantly lower. In addition, we and our subsidiaries purchase natural gas under supply agreements that contain an aggregate credit threshold of $100 million based on our S&P Senior Unsecured Long-Term Debt rating of BBB. Upgrades and downgrades from this BBB rating will increase and decrease the aggregate credit threshold accordingly.

In connection with the development of SESH's 270-mile pipeline project, we have committed that we will advance funds to the joint venture or cause funds to be advanced for our 50% share of the cost to construct the pipeline. We also agreed to provide a letter of credit in an amount up to $400 million for our share of funds that have not been advanced in the event S&P reduces our bond rating below investment grade before we have advanced the required construction funds. However, we are relieved of these commitments (i) to the extent of 50% of any borrowing agreements that the joint venture has obtained and maintains for funding the construction of the pipeline and (ii) to the extent we or our subsidiary participating in the joint venture obtains committed borrowing agreements pursuant to which funds may be borrowed and used for the construction of the pipeline. A similar commitment has been provided by the other party to the joint venture. As of December 31, 2007, our subsidiaries have advanced approximately $198 million to SESH, of which $52 million was in the form of an equity contribution and $146 million was in the form of a loan.

Cross Defaults. Under CenterPoint Energy's revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $50 million by us will cause a default. Pursuant to the indenture governing CenterPoint Energy's senior notes, a payment default by us, in respect of, or an acceleration of, borrowed money and certain other specified types of obligations, in the aggregate principal amount of $50 million will cause a default. As of December 31, 2007, CenterPoint Energy had six series of senior notes aggregating $1.4 billion in principal amount outstanding under this indenture. A default by CenterPoint Energy would not trigger a default under our debt instruments or bank credit facilities.

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

- cash collateral requirements that could exist in connection with certain contracts, including gas purchases, gas price and weather hedging and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, 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 natural gas suppliers;
- increased costs related to the acquisition of natural gas;
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various regulatory actions;
- the ability of RRI and its subsidiaries to satisfy their obligations to us or in connection with the contractual arrangement pursuant to which we are a guarantor;

- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- the outcome of litigation brought by and against us;
- contributions to benefit plans;
- restoration costs and revenue losses resulting from natural disasters such as hurricanes; and
- various other risks identified in “Risk Factors” in Item 1A of this report.

Certain Contractual Limits on Ability to Issue Securities and Borrow Money. Our bank facility and our receivables facility limit our debt as a percentage of our total capitalization to 65%.

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 Statement of Financial Accounting Standards (SFAS) No. 142, “Goodwill and Other Intangible Assets.” No impairment of goodwill was indicated based on our annual analysis as of July 1, 2007. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, 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.

Asset Retirement Obligations

We account for our long-lived assets under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), and Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations — An Interpretation of SFAS No. 143" (FIN 47). SFAS No. 143 and FIN 47 require that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and FIN 47, and costs recovered through the ratemaking process.

We estimate the fair value of asset retirement obligations by calculating the discounted cash flows that are dependent upon the following components:

- *Inflation adjustment* - The estimated cash flows are adjusted for inflation estimates for labor, equipment, materials, and other disposal costs;
- *Discount rate* - The estimated cash flows include contingency factors that were used as a proxy for the market risk premium; and
- *Third party markup adjustments* - Internal labor costs included in the cash flow calculation were adjusted for costs that a third party would incur in performing the tasks necessary to retire the asset.

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 4%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by approximately 3%. At December 31, 2007, our estimated cost of retiring these assets was approximately $62 million.

Unbilled Revenues

Revenues related to natural gas sales and services are generally recognized upon delivery to customers. However, the determination of deliveries 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, deliveries to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

NEW ACCOUNTING PRONOUNCEMENTS

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

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 2(o) to our consolidated financial statements, we participate in CenterPoint Energy's qualified and non-qualified pension plans covering substantially all employees. We expect to record pension income of $2 million for 2008 based on an expected return on plan assets of 8.50% and a discount rate of 6.40% as of December 31, 2007. Pension expense for the year ended December 31, 2007 was $5 million. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plans will impact our future pension expense. We cannot predict with certainty what these factors will be in the future.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Impact of Changes in Interest Rates and Energy Commodity Prices

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

- Commodity price risk results from exposures to changes in spot prices, forward prices and price volatilities of commodities, such as natural gas and other energy commodities risk.
- Interest rate risk primarily results from exposures to changes in the level of borrowings and changes in interest rates.
- Equity price risk results from exposures to changes in prices of individual equity securities.

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

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

Derivative transactions are entered into in our non-trading operations to manage and hedge certain exposures, such as exposure to changes in natural 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

As of December 31, 2007, we had outstanding long-term debt, bank loans and money pool borrowings from affiliates that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $373 million and $449 million at December 31, 2006 and 2007, respectively. If the floating interest rates were to increase by 10% from December 31, 2007 rates, our combined interest expense would increase by approximately $2 million annually.

At December 31, 2006 and 2007, we had outstanding fixed-rate debt aggregating $2.2 billion and $2.8 billion, respectively, in principal amount and having a fair value of $2.3 billion and $2.9 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 $96 million if interest rates were to decline by 10% from their levels at December 31, 2007. 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

We use derivative instruments as economic hedges to offset the commodity price 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 fair value based on a hypothetical 10% movement in energy prices. At December 31, 2007, the recorded fair value of our non-trading energy derivatives was a net liability of $25 million. The net liability consisted of an $8 million net liability associated with price stabilization activities of our Natural Gas Distribution business segment and a net liability of $17 million related to our Competitive Natural Gas Sales and Services business segment. Net assets or liabilities related to the price stabilization activities correspond directly with net over/under recovered gas cost liabilities or assets on the balance sheet. An increase of 10% in the market prices of energy commodities from their December 31, 2007 levels would have increased the fair value of our non-trading energy derivatives net liability by $5 million.

The above analysis of the non-trading energy derivatives utilized for commodity price risk management 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 is expected to be substantially offset by a favorable impact on the underlying hedged physical transactions.

CenterPoint Energy has a Risk Oversight Committee composed of corporate and business segment officers that oversees our commodity price, weather and credit risk activities, including our trading, marketing, risk management services and hedging activities. 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 our risk management policies and procedures and trading limits established by CenterPoint Energy's board of directors.

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

Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp. and subsidiaries (the "Company", an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2007 and 2006, and the related statements of consolidated income, comprehensive income, cash flows and stockholder's equity for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of CenterPoint Energy Resources Corp. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005.

DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2008

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Management has designed its internal control over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with accounting principles generally accepted in the United States of America. Management's assessment included review and testing of both the design effectiveness and operating effectiveness of controls over all relevant assertions related to all significant accounts and disclosures in the financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control — Integrated Framework, our management has concluded that our internal control over financial reporting was effective as of December 31, 2007.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management's report in this annual report.

/s/ DAVID M. MCCLANAHAN

President and Chief Executive Officer

/s/ GARY L. WHITLOCK

Executive Vice President and Chief Financial Officer

March 12, 2008

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CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2005	2006	2007
		(In Millions)	
Revenues	$ 8,070	$ 7,528	$ 7,776
Expenses:			
Natural gas	6,509	5,909	5,995
Operation and maintenance	743	798	800
Depreciation and amortization	198	200	215
Taxes other than income taxes	156	149	140
Total	7,606	7,056	7,150
Operating Income	464	472	626
Other Income (Expense):			
Interest and other finance charges	(176)	(167)	(187)
Other, net	21	18	21
Total	(155)	(149)	(166)
Income Before Income Taxes	309	323	460
Income tax expense	(116)	(116)	(173)
Net Income	$ 193	$ 207	$ 287

See Notes to the Company's Consolidated Financial Statements

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CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2005	2006	2007
		(In Millions)	
Net income	$ 193	$ 207	$ 287
Other comprehensive income (loss), net of tax:			
SFAS No. 158 adjustment (includes a tax benefit of $6)	—	—	13
Net deferred gain from cash flow hedges (net of tax of $9, $11 and $6)	17	22	12
Reclassification of net deferred gain from cash flow hedges realized in net income (net of tax of ($5), ($3) and ($20))	(8)	(7)	(33)
Other comprehensive income (loss)	9	15	(8)
Comprehensive income	$ 202	$ 222	$ 279

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, 2006	December 31, 2007
	(In Millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 5	$ 1
Accounts receivable, net	846	732
Accrued unbilled revenue	356	456
Accounts and notes receivable — affiliated companies	198	82
Inventory	336	430
Non-trading derivative assets	98	38
Deferred tax asset	2	40
Prepaid expenses	14	19
Other	346	216
Total current assets	2,201	2,014
Property, Plant and Equipment, Net	4,639	5,031
Other Assets:		
Goodwill	1,705	1,696
Non-trading derivative assets	21	11
Notes receivable from unconsolidated affiliates	—	148
Other	249	234
Total other assets	1,975	2,089
Total Assets	$ 8,815	$ 9,134
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ 187	$ 232
Current portion of long-term debt	7	307
Accounts payable	928	661
Accounts and notes payable — affiliated companies	386	144
Taxes accrued	115	118
Interest accrued	48	59
Customer deposits	62	59
Non-trading derivative liabilities	141	60
Other	305	186
Total current liabilities	2,179	1,826
Other Liabilities:		
Accumulated deferred income taxes, net	662	778
Non-trading derivative liabilities	80	14
Benefit obligations	138	116
Regulatory liabilities	456	474
Other	213	167
Total other liabilities	1,549	1,549
Long-Term Debt	2,155	2,645
Commitments and Contingencies (Note 8)		
Stockholder's Equity	2,932	3,114
Total Liabilities And Stockholder's Equity	$ 8,815	$ 9,134

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,		
	2005	2006	2007
		(In Millions)	
Cash Flows from Operating Activities:			
Net income	$ 193	$ 207	$ 287
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	198	200	215
Deferred income taxes	32	17	64
Amortization of deferred financing costs	9	8	8
Write-down of natural gas inventory	—	66	11
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(393)	248	14
Accounts receivable/payable, affiliates	10	(19)	(8)
Inventory	(109)	(78)	(105)
Taxes receivable	39	—	—
Accounts payable	326	(262)	(175)
Fuel cost recovery	(129)	111	(93)
Interest and taxes accrued	(23)	(4)	23
Net non-trading derivative assets and liabilities	(12)	(18)	13
Margin deposits, net	51	(156)	65
Other current assets	(5)	(80)	(27)
Other current liabilities	54	29	(16)
Other assets	8	1	(20)
Other liabilities	30	18	(12)
Other, net	(3)	(15)	(3)
Net cash provided by operating activities	276	273	241
Cash Flows from Investing Activities:			
Capital expenditures	(403)	(599)	(676)
Decrease in affiliate notes receivable	42	—	—
Increase in notes receivable from unconsolidated affiliates	—	—	(148)
Investment in unconsolidated affiliates	—	(13)	(39)
Other, net	(11)	(9)	(10)
Net cash used in investing activities	(372)	(621)	(873)
Cash Flows from Financing Activities:			
Increase in short-term borrowings, net	—	187	45
Long-term revolving credit facilities, net	—	—	150
Payments of long-term debt	(372)	(152)	(7)
Proceeds from long-term debt	—	324	650
Increase (decrease) in notes with affiliates, net	288	(103)	(107)
Contribution from parent	171	168	—
Dividends to parent	(100)	(100)	(100)
Debt issuance costs	(1)	(1)	(6)
Other, net	—	(1)	3
Net cash provided by (used in) financing activities	(14)	322	628
Net Decrease in Cash and Cash Equivalents	(110)	(26)	(4)
Cash and Cash Equivalents at Beginning of the Year	141	31	5
Cash and Cash Equivalents at End of the Year	$ 31	$ 5	$ 1
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 181	$ 162	$ 167
Income taxes (refunds)	87	(25)	106
Non-cash transactions:			
Increase in accounts payable related to capital expenditures	$ 14	$ 108	$ —

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

	2005		2006		2007	
	Shares	Amount	Shares	Amount	Shares	Amount
	(In millions, except share amounts)					
Common Stock						
Balance, beginning of year	1,000	$ —	1,000	$ —	1,000	$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		2,232		2,404		2,403
Contribution from (to) parent		171		(3)		—
Other		1		2		3
Balance, end of year		2,404		2,403		2,406
Retained Earnings						
Balance, beginning of year		305		398		505
Net income		193		207		287
Dividend to parent		(100)		(100)		(100)
Balance, end of year		398		505		692
Accumulated Other Comprehensive Income						
Balance, end of year:						
Net deferred gain from cash flow hedges		11		26		5
SFAS No. 158 impact		—		(2)		11
Total accumulated other comprehensive income, end of year		11		24		16
Total Stockholder's Equity		$ 2,813		$ 2,932		$ 3,114

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Background and Basis of Presentation

CenterPoint Energy Resources Corp. (CERC Corp., and, together with its subsidiaries, the Company), owns and operates natural gas distribution systems in six states. Subsidiaries of the Company own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of the Company offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities. CERC Corp. is a Delaware corporation.

The Company is an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

Basis of Presentation

For a description of the Company's reportable business segments, see Note 11.

2. Summary of Significant Accounting Policies

(a) Use of Estimates

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 intercompany transactions and balances are eliminated in consolidation. The Company uses the equity method of accounting for investments in entities in which the Company has an ownership interest between 20% and 50% and exercises significant influence. Such investments were $32 million and $88 million as of December 31, 2006 and 2007, respectively, and are included as part of other noncurrent assets in the Company's Consolidated Balance Sheets. Other investments, excluding marketable securities, are carried at cost.

(c) Revenues

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

(d) Long-Lived Assets and Intangibles

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

	Weighted Average Useful Lives (Years)	December 31, 2006	December 31, 2007
		(In millions)	
Natural Gas Distribution	31	$ 2,875	$ 3,065
Competitive Natural Gas Sales and Services	24	53	59
Interstate Pipelines	57	1,943	2,194
Field Services	51	429	493
Other property	13	36	26
Total		5,336	5,837
Accumulated depreciation and amortization:			
Natural Gas Distribution		462	590
Competitive Natural Gas Sales and Services		9	9
Interstate Pipelines		176	160
Field Services		31	29
Other property		19	18
Total accumulated depreciation and amortization		697	806
Property, plant and equipment, net		$ 4,639	$ 5,031

Goodwill by reportable business segment as of December 31, 2006 and 2007 is as follows (in millions):

	December 31, 2006	December 31, 2007
Natural Gas Distribution	$ 746	$ 746
Interstate Pipelines	579	579
Competitive Natural Gas Sales and Services	335	335
Field Services	25	25
Other Operations (1)	20	11
Total	$ 1,705	$ 1,696

(1) In December 2007, the Company determined that $9 million of tax benefits not previously established were associated with a prior year acquisition. In accordance with Emerging Issues Task Force (EITF) Issue No. 93-7, "Uncertainties Related to Income Taxes in a Purchase Business Combination," the adjustment was applied to decrease the remaining goodwill attributable to that acquisition.

The Company performs its goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The impairment evaluation for goodwill is performed by using a two-step process. In the first step, the fair value of each reporting unit is compared with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is generally determined on the basis of discounted future cash flows. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference.

The Company performed the test at July 1, 2007, the Company's annual impairment testing date, and determined that no impairment charge for goodwill was required.

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

(e) Regulatory Assets and Liabilities

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

The following is a list of regulatory assets/liabilities reflected on the Company's Consolidated Balance Sheets as of December 31, 2006 and 2007:

	December 31,	
	2006	2007
	(In millions)	
Regulatory assets in other long-term assets	$ 50	$ 53
Regulatory liabilities	(456)	(474)
Net	$ (406)	$ (421)

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

The Company's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2006 and 2007, these removal costs of $424 million and $445 million, respectively, are classified as regulatory liabilities in the Consolidated Balance Sheets. The Company adopted Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), effective December 31, 2005. FIN 47 clarifies that an entity must record a liability for a "conditional" asset retirement obligation if the fair value of the obligation can be reasonably estimated. The Company has identified conditional asset retirement obligations in the natural gas distribution segment that exist due to requirements of the U.S. Department of Transportation to cap and purge certain mains upon retirement. The fair value of these obligations is recorded as a liability on a discounted basis with a corresponding increase to the related asset. Over time, the liabilities are accreted for the change in the present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The adoption of FIN 47, effective December 31, 2005, resulted in the recognition of an asset retirement obligation liability of $65 million, an increase in net property, plant and equipment of $31 million and a $34 million increase in net regulatory assets. Upon adoption of FIN 47, the portion of the removal costs that relates to this asset retirement obligation has been reclassified from a regulatory liability to an asset retirement liability, which is included in other liabilities in the Consolidated Balance Sheets. At December 31, 2006 and 2007, the Company had recorded asset retirement obligations of $66 million and $62 million, respectively.

(f) Depreciation and Amortization Expense

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

The following table presents depreciation and amortization expense for 2005, 2006 and 2007:

	Year Ended December 31,		
	2005	2006	2007
		(In millions)	
Depreciation expense	$ 180	$ 181	$ 193
Amortization expense	18	19	22
Total depreciation and amortization expense	$ 198	$ 200	$ 215

(g) Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for subsidiaries that apply SFAS No. 71. Interest and AFUDC for subsidiaries that apply SFAS No. 71 are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During 2005, 2006 and 2007, the Company capitalized interest and AFUDC of $1 million, $6 million and $12 million, respectively.

(h) Income Taxes

The Company is included in the consolidated income tax returns of CenterPoint Energy. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. Pursuant to the tax sharing agreement with CenterPoint Energy, in 2005 and 2006, the Company received allocations of CenterPoint Energy's tax benefits (expense) totaling $171 million and $(3) million, respectively.

The Company uses the asset and liability method of accounting for deferred income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes". Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance is established against deferred tax assets for which management believes realization is not considered more likely than not. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy.

Prior to 2007, the Company evaluated uncertain income tax positions and recorded a tax liability for those positions that management believed were probable of an unfavorable outcome and could be reasonably estimated. Effective January 1, 2007, the Company accounts for the tax effects of uncertain income tax positions in accordance with FIN 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109" (FIN 48). The Company recognizes interest and penalties as a component of income tax expense. For additional information regarding income taxes, see Note 7.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $32 million and $37 million at December 31, 2006 and 2007, respectively. The provision for doubtful accounts in the Company's Statements of Consolidated Income for 2005, 2006 and 2007 was $37 million, $37 million and $42 million, respectively.

In October 2007, the Company amended its receivables facility and extended the termination date to October 28, 2008. The facility size will range from $150 million to $375 million during the period from September 30, 2007 to the October 28, 2008 termination date. The variable size of the facility was designed to track the seasonal pattern of receivables in the Company's natural gas businesses. At December 31, 2007, the facility size was $300 million. Commencing with an October 2006 amendment to the receivables facility, the provisions for sale accounting under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," were no longer met. Accordingly, advances received by the Company upon the sale of receivables are accounted for as short-term borrowings as of December 31, 2006 and 2007. As of December 31, 2006 and 2007, $187 million and $232 million, respectively, was advanced for the purchase of receivables under the Company's receivables facility.

Funding under the receivables facility averaged $166 million and $79 million in 2005 and 2006, respectively. Sales of receivables were approximately $2.0 billion and $555 million in 2005 and 2006, respectively.

(j) Inventory

Inventory consists principally of materials and supplies and natural gas. Materials and supplies are valued at the lower of average cost or market. Natural gas inventories of the Company's Competitive Natural Gas Sales and Services business segment are also primarily valued at the lower of average cost or market. Natural gas inventories of the Company's Natural Gas Distribution business segment are primarily valued at weighted average cost. During

2006 and 2007, the Company recorded $66 million and $11 million, respectively, in write-downs of natural gas inventory to the lower of average cost or market.

	December 31, 2006	December 31, 2007
	(In millions)	
Materials and supplies	$ 31	$ 35
Natural gas	305	395
Total inventory	$ 336	$ 430

(k) Derivative Instruments

The Company utilizes derivative instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices and weather on its operating results and cash flows. Such contracts are recognized in the Company's Consolidated Balance Sheets at their fair value unless the Company elects the normal purchase and sales exemption for qualified physical transactions. A derivative contract may be designated as a normal purchase or sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business. If derivative contracts are designated as a cash flow hedge according to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), the effective portions of the changes in their fair values are reflected initially as a separate component of shareholders' equity and subsequently recognized in income at the same time the hedged item impacts earnings. The ineffective portions of changes in fair values of derivatives designated as hedges are immediately recognized in income. Changes in other derivatives not designated as normal or as a cash flow hedge are recognized in income as they occur. The Company does not enter into or hold derivative instruments for trading purposes.

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

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

(l) Environmental Costs

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

(m) Statements of Consolidated Cash Flows

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

(n) New Accounting Pronouncements

In July 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertain income tax positions and requires the Company to recognize management's best estimate of the impact of a tax position if it is considered "more likely than not," as defined in SFAS No. 5, "Accounting for Contingencies," of being sustained on audit based solely on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The cumulative effect of adopting FIN 48 as of January 1, 2007 was a credit to retained earnings of less than $1 million.

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements” (SFAS No. 157). SFAS No. 157 establishes a framework for measuring fair value and requires expanded disclosure about the information used to measure fair value. The statement applies whenever other statements require or permit assets or liabilities to be measured at fair value. The statement does not expand the use of fair value accounting in any new circumstances and is effective for the Company for the year ended December 31, 2008 and for interim periods included in that year, with early adoption encouraged. The Company will adopt SFAS No. 157 on January 1, 2008, for its financial assets and liabilities, which primarily consist of derivatives the Company records in accordance with SFAS No. 133, and on January 1, 2009, for its non-financial assets and liabilities. For its financial assets and liabilities, the Company expects that the adoption of SFAS No. 157 will primarily impact its disclosures and will not have a material impact on its financial position, results of operations and cash flows. The Company is currently evaluating the impact with respect to its non-financial assets and liabilities.

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115” (SFAS No. 159). SFAS No. 159 permits the Company to choose, at specified election dates, to measure eligible items at fair value (the “fair value option”). The Company would report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting period. This accounting standard is effective as of the beginning of the first fiscal year that begins after November 15, 2007 but is not required to be applied. The Company currently has no plans to apply SFAS No. 159.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), “Business Combinations” (SFAS No. 141R). SFAS No. 141R will significantly change the accounting for business combinations. Under SFAS No. 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. SFAS No. 141R also includes a substantial number of new disclosure requirements and applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. As the provisions of SFAS No. 141R are applied prospectively, the impact to the Company cannot be determined until the transactions occur.

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements — An Amendment of ARB No. 51” (SFAS No. 160). SFAS No. 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This accounting standard is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company will adopt SFAS No. 160 as of January 1, 2009. The Company expects that the adoption of SFAS No. 160 will not have a material impact on its financial position, results of operations and cash flows.

(o) Employee Benefit Plans

Pension Plans

Substantially all of the Company’s employees participate in CenterPoint Energy’s qualified non-contributory defined benefit 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 $15 million, $16 million and $5 million for the years ended December 31, 2005, 2006 and 2007, respectively.

In addition to the plan, the Company participates in CenterPoint Energy's non-qualified benefit restoration plan, which allows participants to retain the benefits to which they would have been entitled under the qualified pension plan except for federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. The expense associated with the non-qualified pension plan was less than $1 million for each of the years ended December 31, 2005, 2006 and 2007.

Savings Plan

The Company participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 16% of compensation. CenterPoint Energy matches 75% of the first 6% of each employee's compensation contributed. CenterPoint Energy may contribute an additional discretionary match of up to 50% of the first 6% of each employee's compensation contributed. These matching contributions are fully vested at all times. CenterPoint Energy allocates to the Company the savings plan benefit expense related to the Company's employees. Savings plan benefit expense was $17 million for each of the years ended December 31, 2005, 2006 and 2007.

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.

Upon adoption of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106 and 132 (R)" (SFAS No. 158), at December 31, 2006, the Company recorded increases (decreases) in the following balance sheet accounts: regulatory assets — $3 million, other current liabilities — $7 million, accumulated deferred income taxes, net — ($20) million, benefit obligations — $18 million and accumulated other comprehensive loss — $2 million. The adoption of SFAS No. 158 did not impact the income statement recognition provisions of benefit plan accounting.

The net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2005	2006	2007
		(In millions)	
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	8	7	7
Expected return on plan assets	(2)	(1)	(1)
Amortization of prior service cost	2	2	2
Other	1	1	—
Net postretirement benefit cost	$ 10	$ 10	$ 9

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

	Year Ended December 31,		
	2005	2006	2007
Discount rate	5.75%	5.70%	5.85%
Expected return on plan assets	8.00%	4.80%	4.50%

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 plan's benefit obligation, plan assets and funded status for 2006 and 2007. The measurement dates for plan assets and obligations were December 31, 2006 and 2007.

	Year Ended December 31, 2006	Year Ended December 31, 2007
	(In millions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 132	$ 134
Service cost	1	1
Interest cost	7	7
Benefit enhancement	1	—
Benefits paid	(22)	(20)
Plan amendment	8	—
Medicare reimbursement	3	3
Participant contributions	4	4
Actuarial loss	—	(10)
Accumulated benefit obligation, end of year	$ 134	$ 119
Change in Plan Assets		
Plan assets, beginning of year	$ 20	$ 20
Benefits paid	(22)	(20)
Employer contributions	16	15
Participant contributions	4	4
Actual investment return	2	1
Plan assets, end of year	$ 20	$ 20
Amounts Recognized in Balance Sheets		
Current liabilities-other	$ (7)	$ (6)
Other liabilities-benefit obligations	(107)	(93)
Net liability, end of year	$ (114)	$ (99)
Actuarial Assumptions		
Discount rate	5.85%	6.40%
Expected long-term return on assets	4.50%	4.50%
Healthcare cost trend rate assumed for the next year	7.00%	7.00%
Prescription cost trend rate assumed for the next year	13.00%	13.00%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.50%	5.50%
Year that the healthcare rate reaches the ultimate trend rate	2011	2012
Year that the prescription drug rate reaches the ultimate trend rate	2014	2015

The discount rate was determined by reviewing yields on high-quality bonds that receive one of the two highest ratings given by a recognized rating agency and expected duration of obligations specific to the characteristics of our plans.

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.

For measurement purposes, healthcare costs are assumed to increase 7% during 2008, after which this rate decreases until reaching the ultimate rate of 5.50% in 2012. Prescription drug costs are assumed to increase 13% in 2008, after which this rate decreases until reaching the ultimate rate of 5.50% in 2015.

Amounts recognized in accumulated other comprehensive (income) loss consist of the following:

	Year Ended December 31, 2006	Year Ended December 31, 2007
	(In millions)	
Unrecognized actuarial loss	$ 8	$ 3
Unrecognized prior service cost	14	12
	22	15
Less deferred tax benefit (1)	(20)	(26)
Net amount recognized in accumulated other comprehensive (income) loss	$ 2	$ (11)

(1) The Company's postretirement benefit obligation is reduced by the impact of non-taxable government subsidies under the Medicare Prescription Drug Act. Because the subsidies are non-taxable, the temporary difference used in measuring the deferred tax impact is determined on the unrecognized losses excluding such subsidies. Accordingly, the unrecognized losses used for determining deferred taxes were $54 million and $64 million as of December 31, 2006 and 2007, respectively.

The changes in plan assets and benefit obligations recognized in other comprehensive income during 2007 are as follows:

	Postretirement Benefits
	(In millions)
Net gain	$ (5)
Amortization of prior service cost	(2)
Total recognized in other comprehensive income	$ (7)

The total recognized in net periodic costs and other comprehensive income was an expense of $2 million for postretirement benefits for the year ended December 31, 2007.

The amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost during 2008 are as follows:

	Postretirement Benefits
	(In millions)
Unrecognized prior service cost	$ 2
Amounts in other comprehensive income to be recognized as net periodic cost in 2008	$ 2

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 the postretirement benefit obligation	$ 5	$ (4)
Effect on the total of service and interest cost	—	—

The following table displays the weighted average asset allocations as of December 31, 2006 and 2007 for the Company's postretirement benefit plan:

	December 31, 2006	December 31, 2007
Domestic equity securities	6%	6%
Debt securities	93	93
Cash	1	1
Total	100%	100%

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

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

Domestic equity securities	0-10%
Debt securities	90-100%
Cash	0-2%

The Company expects to contribute $14 million to its postretirement benefits plan in 2008. The following benefit payments are expected to be paid by the postretirement benefit plan:

	Postretirement Benefit Plan	
	Benefit Payments	Medicare Subsidy Receipts
	(in millions)	
2008	$10	$(1)
2009	10	(1)
2010	10	(1)
2011	11	(2)
2012	11	(2)
2013-2017	58	(9)

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 cost was $3 million each year in 2005 and 2006. The Company recorded postemployment income of $2 million in 2007. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2006 and 2007, was $20 million and $17 million, respectively, related to postemployment benefits.

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 2005, 2006 and 2007, the benefits expense relating to these programs was less than $1 million each year. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2006 and 2007, was $5 million and $4 million, respectively, relating to deferred compensation plans.

(p) Other Current Assets and Liabilities

Included in other current assets on the Consolidated Balance Sheets at December 31, 2006 and 2007 was $113 million and $47 million, respectively, of margin deposits and $110 million and $53 million, respectively of under recovered gas cost. Included in other current liabilities on the Consolidated Balance Sheets at December 31, 2006 and 2007 was $123 million and $30 million, respectively, of over recovered gas cost.

3. Regulatory Matters

(a) Rate Cases

Arkansas. In January 2007, the Company's natural gas distribution business (Gas Operations) filed an application with the Arkansas Public Service Commission (APSC) to change its natural gas distribution rates in order to increase its annual base revenues by approximately $51 million. Gas Operations subsequently agreed to reduce its request to approximately $40 million. As part of its filing, Gas Operations also proposed a revenue stabilization tariff (also known as decoupling) that would help stabilize revenues and eliminate the potential conflict between its efforts to earn a reasonable return on invested capital while promoting energy efficiency initiatives.

In September 2007, the APSC staff and Gas Operations entered into and filed with the APSC a Stipulation and Settlement Agreement (Settlement Agreement) under which the annual base revenues of Gas Operations would increase by approximately $20 million, and a revenue stabilization tariff would be allowed to go into effect, with an authorized rate of return on equity of 9.65% (reflecting a 10 basis point reduction for the implementation of the revenue stabilization tariff). The other parties to the proceeding agreed not to oppose the Settlement Agreement. In October 2007, the APSC issued an order approving the Settlement Agreement, and the new rates became effective with bills rendered on and after November 1, 2007.

Texas. In December 2006, Gas Operations filed a statement of intent with the Railroad Commission of Texas (Railroad Commission) seeking to implement an increase in miscellaneous service charges and to allow recovery of the costs of financial hedging transactions through its purchased gas cost adjustment in the environs of its Texas Coast service territory. After approval of the filing by the Railroad Commission, the new service charges were implemented in the second quarter of 2007.

In response to an explosion resulting from the failure of a certain type of compression coupling on another company's natural gas distribution system in Texas, the Railroad Commission has begun a rulemaking focusing on leak surveys, leak grading and the replacement of specific types of compression couplings. In addition, the Railroad Commission issued a directive in November 2007 requiring the removal of service risers known to have compression fittings that do not meet certain performance specifications. After reviewing the Company's records as required by the directive, Gas Operations has no indication that it has the type of coupling described in that directive. However, at this time the Company does not know what additional requirements may result from the pending Railroad Commission rulemaking or what impacts on its gas operations may result from any future regulatory initiatives adopted with respect to this issue.

In the first quarter of 2008, Gas Operations filed a request to change its rates with the Railroad Commission and the 47 cities in its Texas Coast service territory. The request seeks to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Texas Coast service territory. The effect of the requested rate changes will be to increase the Texas Coast service territory's revenues by approximately $7 million per year.

Minnesota. In November 2005, Gas Operations filed a request with the Minnesota Public Utilities Commission (MPUC) to increase annual base rates by approximately $41 million. In December 2005, the MPUC approved an interim rate increase of approximately $35 million that was implemented January 1, 2006. In January 2007, the MPUC issued a final order granting a rate increase of approximately $21 million and approving a $5 million affordability program to assist low-income customers, the actual cost of which will be recovered in rates in addition to the $21 million rate increase. Final rates were implemented beginning May 1, 2007, and Gas Operations completed refunding to customers the proportional share of the excess of the amounts collected in interim rates over the amount allowed by the final order in the second quarter of 2007.

In November 2006, the MPUC denied a request filed by Gas Operations for a waiver of MPUC rules in order to allow Gas Operations to recover approximately $21 million in unrecovered purchased gas costs related to periods prior to July 1, 2004. Those unrecovered gas costs were identified as a result of revisions to previously approved calculations of unrecovered purchased gas costs. Following that denial, Gas Operations recorded a $21 million adjustment to reduce pre-tax earnings in the fourth quarter of 2006 and reduced the regulatory asset related to these costs by an equal amount. In March 2007, following the MPUC's denial of reconsideration of its ruling, Gas Operations petitioned the Minnesota Court of Appeals for review of the MPUC's decision. That court heard oral arguments on the appeal in February 2008 and is expected to render its decision within 90 days of that hearing. No prediction can be made as to the ultimate outcome of this matter.

4. Related Party Transactions

The Company participates in a "money pool" through which it 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 net funding requirements of the money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper. The Company had money pool borrowings of $186 million and $67 million at December 31, 2006 and 2007, which are included in accounts and notes payable—

affiliated companies in the Consolidated Balance Sheets. At December 31, 2007, the Company's money pool borrowings had a weighted average interest rate of 5.188%.

For the years ended December 31, 2005, 2006 and 2007, the Company had net interest income (expense) related to affiliate borrowings of $3 million, $(2) million and $(3) million, respectively.

CenterPoint Energy provides some corporate services to the Company. The costs of services have been charged directly to the Company using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin 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 $129 million, $133 million and $133 million for 2005, 2006 and 2007, respectively, and are included primarily in operation and maintenance expenses.

Pursuant to the tax sharing agreement with CenterPoint Energy, the Company received allocations of CenterPoint Energy's tax benefits (expense) of $171 million and $(3) million for 2005 and 2006, respectively, which was recorded in additional paid-in capital.

In each of 2005, 2006 and 2007, the Company paid dividends of $100 million to its parent.

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 instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices, weather and interest rates on its operating results and cash flows.

(a) Non-Trading Activities

Cash Flow Hedges. The Company enters into certain derivative instruments that qualify as cash flow hedges under SFAS No. 133. The objective of these derivative instruments is to hedge the price risk associated with natural gas purchases and sales to reduce cash flow variability related to meeting the Company's wholesale and retail customer obligations. During the years ended December 31, 2005, 2006 and 2007, hedge ineffectiveness resulted in a loss of $2 million, a gain of $2 million and a loss of less than $1 million, respectively, from derivatives that qualify for and are designated 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 being hedged will not occur, the Company realizes in net income the deferred gains and losses previously recognized in accumulated other comprehensive loss. The Company recognized a gain of $2 million in 2007 because it became probable that certain anticipated transactions being hedged would not occur. When an anticipated transaction being hedged affects earnings, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in the Statements of Consolidated Income under the "Expenses" 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, 2007, the Company expects $7 million ($4 million after-tax) in accumulated other comprehensive income to be reclassified as a decrease in Natural gas expense during the next twelve months.

The length of time the Company is hedging its exposure to the variability in future cash flows using derivative instruments that have been designated and have qualified as cash flow hedging instruments is primarily a year, with a limited amount up to two years. The Company's policy is not to exceed ten years in hedging its exposure.

Other Derivative Instruments. The Company enters into certain derivative instruments to manage physical commodity price risks that do not qualify or are not designated as cash flow or fair value hedges under SFAS No. 133. The Company utilizes these financial instruments to manage physical commodity price risks and does not engage in proprietary or speculative commodity trading. During the years ended December 31, 2005, 2006 and 2007, the Company recognized unrealized net gains of $2 million and $34 million and net losses of $10 million, respectively. These derivative gains and losses are included in the Statements of Consolidated Income under the “Expenses” caption “Natural gas.”

Weather Derivatives. The Company has weather normalization or other rate mechanisms that mitigate the impact of weather in certain of its Gas Operations jurisdictions. The remaining Gas Operations jurisdictions, Minnesota, Mississippi and Texas, do not have such mechanisms. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of these operations.

In 2007, the Company entered into heating-degree day swaps to mitigate the effect of fluctuations from normal weather on its financial position and cash flows for the 2007/2008 winter heating season. The swaps are based on ten-year normal weather and provide for a maximum payment by either party of $18 million. Through December 31, 2007, the existence of the swaps had no material impact on the Company’s earnings or cash flow.

(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, 2006 and 2007 (in millions):

	December 31, 2006		December 31, 2007	
	Investment Grade(1)	Total	Investment Grade(1)	Total
Energy marketers	$ 22	$ 27	$ 16	$ 18
Financial institutions	51	51	25	25
Other	41	41	3	7
Total	$ 114	$ 119	$ 44	$ 50

(1) “Investment grade” is primarily determined using publicly available credit ratings along with the consideration of credit support (such as parent company guaranties) and collateral, which encompass cash and standby letters of credit. For unrated counterparties, the Company performs financial statement analysis, considering contractual rights and restrictions and collateral, to create a synthetic credit rating.

6. Short-term Borrowings and Long-term Debt

	December 31, 2006		December 31, 2007	
	Long-Term	Current(1)	Long-Term	Current(1)
	(In millions)			
Short-term borrowings:				
CERC Corp. receivables facility	$ —	$ 187	$ —	$ 232
Long-term debt:				
Convertible subordinated debentures 6.00% due 2012	56	7	50	7
Senior notes 5.95% to 7.875% due 2008 to 2016	2,097	—	2,447	300
Bank loans due 2012(2)	—	—	150	—
Unamortized discount and premium(3)	2	—	(2)	—
Total long-term debt	2,155	7	2,645	307
Total debt	$ 2,155	$ 194	$ 2,645	$ 539

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

(2) Classified as long-term debt because the termination date of the facility under which the funds were borrowed is more than one year beyond the dates referenced in the table.

(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 $4 million and $3 million at December 31, 2006 and 2007, respectively, which is being amortized over the respective remaining term of the related long-term debt.

(a) Short-term Borrowings

In October 2007, the Company amended its receivables facility and extended the termination date to October 28, 2008. The facility size will range from $150 million to $375 million during the period from September 30, 2007 to the October 28, 2008 termination date. The variable size of the facility was designed to track the seasonal pattern of receivables in the Company's natural gas businesses. At December 31, 2007, the facility size was $300 million. As of December 31, 2006 and December 31, 2007, $187 million and $232 million, respectively, was advanced for the purchase of receivables under the Company's receivables facility. As of December 31, 2007, advances had an interest rate of 5.36%.

(b) Long-term Debt

Senior Notes. In February 2007, the Company issued $150 million aggregate principal amount of senior notes due in February 2037 with an interest rate of 6.25%. The proceeds from the sale of the senior notes were used to repay advances for the purchase of receivables under the Company's receivables facility. Such repayment provided increased liquidity and capital resources for the Company's general corporate purposes.

In October 2007, the Company issued $250 million aggregate principal amount of 6.125% senior notes due in November 2017 and $250 million aggregate principal amount of 6.625% senior notes due in November 2037. The proceeds from the sale of the senior notes were used for general corporate purposes, including repayment or refinancing of debt, including $300 million of the Company's 6.5% senior notes due February 1, 2008, capital expenditures, working capital and loans to or investments in affiliates. Pending application of the proceeds for these purposes, the Company repaid borrowings under its revolving credit and receivables facilities.

Revolving Credit Facility. In June 2007, the Company entered into an amended and restated bank credit facility. The amended facility is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility's first drawn cost remains at London Interbank Offered Rate (LIBOR) plus 45 basis points based on the Company's current credit ratings. The facility contains covenants, including a debt to total capitalization covenant of 65%. Under the credit facility, an additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on the Company's credit rating.

As of December 31, 2007, the Company had $150 million of borrowings and approximately $13 million of outstanding letters of credit under its $950 million credit facility. The Company had no commercial paper outstanding at December 31, 2007. The Company was in compliance with all debt covenants as of December 31, 2007.

Maturities. The Company's consolidated maturities of long-term debt and sinking fund requirements are $307 million in 2008, $6 million in 2009, $6 million in 2010, $557 million in 2011 and $181 million in 2012.

7. Income Taxes

The components of the Company's income tax expense (benefit) are as follows:

	Year Ended December 31,		
	2005	2006	2007
		(In millions)	
Current:			
Federal	$ 82	$ 97	$ 81
State	2	36	28
Total current	84	133	109
Deferred:			
Federal	1	(22)	58
State	31	5	6
Total deferred	32	(17)	64
Income tax expense	$ 116	$ 116	$ 173

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

	Year Ended December 31, 2005	2006	2007
		(In millions)	
Income before income taxes	$ 309	$ 323	$ 460
Federal statutory rate	35%	35%	35%
Income tax expense at statutory rate	108	113	161
Increase (decrease) in tax resulting from:			
State income taxes, net of valuation allowances and federal income tax benefit	22	27	22
Decrease in settled and uncertain income tax positions	(13)	(20)	(8)
Other, net	(1)	(4)	(2)
Total	8	3	12
Income tax expense	$ 116	$ 116	$ 173
Effective income tax rate	37.4%	36.1%	37.6%

The tax effects of temporary differences that give rise to significant portions of deferred tax assets and liabilities are as follows:

	December 31, 2006	2007
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 16	$ 16
Deferred gas costs	—	26
Total current deferred tax assets	16	42
Non-current:		
Employee benefits	78	87
Operating and capital loss carryforwards	27	24
Deferred gas costs	58	—
Other	48	24
Total non-current deferred tax assets before valuation allowance	211	135
Valuation allowance	(22)	(18)
Total non-current deferred tax assets	189	117
Total deferred tax assets	205	159
Deferred tax liabilities:		
Current:		
Non-trading derivative liabilities, net	14	2
Total current deferred tax liabilities	14	2
Non-current:		
Depreciation	822	851
Regulatory liability, net	13	16
Other	16	28
Total non-current deferred tax liabilities	851	895
Total deferred tax liabilities	865	897
Accumulated deferred income taxes, net	$ 660	$ 738

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.

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2007 the Company has approximately $181 million of state net operating loss carryforwards which expire in various years between 2008 and 2027. A valuation allowance has been established for approximately $79 million of the state net operating loss carryforwards that may not be realized. The Company has a state tax credit carryfoward of approximately $3 million which expires in 2026.

At December 31, 2007 the Company has approximately $174 million of state capital loss carryforwards that expire in 2017 for which a valuation allowance has been established.

Uncertain Income Tax Positions. The Company adopted the provisions of FIN 48 on January 1, 2007. The cumulative effect of adopting FIN 48 as of January 1, 2007 was a credit to retained earnings of less than $1 million. A reconciliation of the change in unrecognized tax benefits from January 1, 2007 to December 31, 2007 is as follows (in millions):

Balance at January 1, 2007	$	1
Tax positions related to prior years:		
Reductions		(10)
Settlements		(2)
Balance at December 31, 2007	$	(11)

The Company has $1 million of unrecognized tax benefits that, if recognized, would reduce the effective income tax rate. The Company recognizes interest and penalties as a component of income tax expense. In 2007 the Company recognized a benefit for interest of approximately $4 million on uncertain income tax positions in the Statements of Consolidated Income. The Consolidated Balance Sheets include an interest receivable (liability) for ($1) million and $3 million at January 1, 2007 and December 31, 2007, respectively. The Company does not expect the amount of unrecognized tax benefits to change significantly over the next 12 months.

Tax Audits and Settlements. CenterPoint Energy's consolidated federal income tax returns have been audited and settled through the 1996 tax year. The Company is currently under examination by the Internal Revenue Service (IRS) for tax years 1997 through 2005 and is at various stages of the examination process. The Company has considered the effects of these examinations in its accrual for settled issues and liability for uncertain income tax positions as of December 31, 2007.

The Company reached a tentative settlement with the IRS for a number of tax issues in the fourth quarter of 2006, resulting in a reduction in income tax expense for 2006 of approximately $20 million.

8. Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to the Company's Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, 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, 2006 and December 31, 2007 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. Natural gas supply commitments also include natural gas transportation contracts that do not meet the definition of a derivative. As of December 31, 2007, minimum payment obligations for natural gas supply commitments are approximately $743 million in 2008, $285 million in 2009, $278 million in 2010, $280 million in 2011, $270 million in 2012 and $1.2 billion in 2013 and thereafter.

(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):

2008	$	15
2009		13
2010		9
2011		7
2012		6
2013 and beyond		14
Total	$	64

Total rental expense for all operating leases was $32 million, $51 million and $43 million in 2005, 2006 and 2007, respectively.

(c) Capital Commitments

Carthage to Perryville. In 2007, CenterPoint Energy Gas Transmission Company (CEGT) completed phases one and two of its Carthage to Perryville pipeline project with a total capacity of 1.25 billion cubic feet (Bcf) per day.

In May 2007, CEGT received Federal Energy Regulatory Commission (FERC) approval for the third phase of the project to expand capacity of the pipeline to 1.5 Bcf per day by adding additional compression and operating at higher pressures, and in July 2007, CEGT received approval from the Pipeline and Hazardous Materials Administration (PHMSA) to increase the maximum allowable operating pressure. The PHMSA's approval contained certain conditions and requirements, which CEGT expects to complete in the first quarter of 2008. CEGT has executed contracts for approximately 150 million cubic feet (MMcf) per day of the 250 MMcf per day phase three expansion. The third phase is projected to be in-service in the second quarter of 2008. The additional cost in 2008 to complete phase three is expected to be approximately $10 million.

During the four-year period subsequent to the in-service date of the pipeline, XTO Energy, CEGT's anchor shipper, can request, and subject to mutual negotiations that meet specific financial parameters and to FERC approval, CEGT would construct a 67-mile extension from CEGT's Perryville hub to an interconnect with Texas Eastern Gas Transmission at Union Church, Mississippi.

Southeast Supply Header. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., a wholly owned subsidiary of the Company, and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture (Southeast Supply Header or SESH) to construct, own and operate a 270-mile pipeline with a capacity of approximately 1 Bcf per day that will extend from CEGT's Perryville hub in northeast Louisiana to an interconnection in southern Alabama with Gulfstream Natural Gas System, which is 50% owned by an affiliate of Spectra. The Company accounts for its 50% interest in SESH as an equity investment. As of December 31, 2007, subsidiaries of CERC Corp. have advanced approximately $198 million to SESH, of which $52 million was in the form of an equity contribution and $146 million was in the form of a loan. In 2006, SESH signed agreements with shippers for firm transportation services, which subscribed capacity of 945 MMcf per day. Additionally, SESH and Southern Natural Gas (SNG) have executed a definitive agreement that provides for SNG to jointly own the first 115 miles of the pipeline. Under the agreement, SNG will own an undivided interest in the portion of the pipeline from Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter was increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that will increase the jointly owned capacity up to 500 MMcf per day, subject to FERC approval.

An application to construct, own and operate the pipeline was filed with the FERC in December 2006. In September 2007, the FERC issued the certificate authorizing the construction of the pipeline. This FERC approval does not include the expansion capacity that would take SNG to 500 MMcf per day. SESH began construction in November 2007. SESH expects to complete construction of the pipeline as approved by the FERC in the second half of 2008. SESH's net costs after SNG's contribution are estimated to have increased to approximately $1 billion.

(d) Legal, Environmental and Other Matters

Legal Matters

Natural Gas Measurement Lawsuits. CERC Corp. and certain of its subsidiaries are defendants in a lawsuit 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 October 2006, the judge considering this matter granted the defendants' motion to dismiss the suit on the ground that the court lacked subject matter jurisdiction over the claims asserted. The plaintiff has sought review of that dismissal from the Tenth Circuit Court of Appeals, where the matter remains pending.

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

Gas Cost Recovery Litigation. In October 2002, a lawsuit was filed on behalf of certain ratepayers of the Company in state district court in Wharton County, Texas against the Company, CenterPoint Energy, Entex Gas Marketing Company (EGMC), and certain non-affiliated companies alleging fraud, violations of the Texas Deceptive Trade Practices Act, violations of the Texas Utilities Code, civil conspiracy and violations of the Texas Free Enterprise and Antitrust Act with respect to rates charged to certain consumers of natural gas in the State of Texas. The plaintiffs initially sought certification of a class of Texas ratepayers, but subsequently dropped their request for class certification. The plaintiffs later added as defendants CenterPoint Energy Marketing Inc., CEGT, United Gas, Inc., Louisiana Unit Gas Transmission Company, CenterPoint Energy Pipeline Services, Inc. (CEPS), and CenterPoint Energy Trading and Transportation Group, Inc., all of which are subsidiaries of the Company, and other non-affiliated companies. In February 2005, the case was removed to federal district court in Houston, Texas, and in March 2005, the plaintiffs voluntarily dismissed the case and agreed not to refile the claims asserted unless the Miller County case described below is not certified as a class action or is later decertified.

In October 2004, a lawsuit was filed on behalf of certain ratepayers of the Company in Texas and Arkansas in circuit court in Miller County, Arkansas against the Company, CenterPoint Energy, EGMC, CEGT, CenterPoint Energy Field Services (CEFS), CEPS, Mississippi River Transmission Corp. (MRT) and other non-affiliated companies alleging fraud, unjust enrichment and civil conspiracy with respect to rates charged to certain consumers of natural gas in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. Subsequently, the plaintiffs dropped as defendants CEGT and MRT. The plaintiffs seek class certification, but the proposed class has not been certified. In June 2007, the Arkansas Supreme Court determined that the Arkansas claims are within the sole and exclusive jurisdiction of the APSC. Also in June 2007, the Company, CenterPoint Energy, EGMC and other defendants in the Miller County case filed a petition in a district court in Travis County, Texas seeking a determination that the Railroad Commission has original exclusive jurisdiction over the Texas claims asserted in the Miller County case. In August 2007, the Miller County court stayed but refused to dismiss the Arkansas claims. Also in August 2007, the Arkansas plaintiff initiated a complaint at the APSC seeking a decision concerning the extent of the APSC's jurisdiction over the Miller County case and an investigation into the merits of the allegations asserted in his complaint with respect to the Company. In September 2007, the Company, CenterPoint Energy, EGMC and other defendants in the Miller County case initiated proceedings in the Arkansas Supreme Court to direct the Miller County court to dismiss the entire case on the grounds that the plaintiffs' claims are within the exclusive jurisdiction of the APSC or Railroad Commission, as applicable. In October 2007, CEFS and CEPS were joined as parties to the Travis County case. In February 2008, the Arkansas Supreme Court granted the Company's request and ordered that the case be dismissed. The plaintiffs have thirty days to request rehearing from the Arkansas Supreme Court.

In February 2003, a lawsuit was filed in state court in Caddo Parish, Louisiana against the Company with respect to rates charged to a purported class of certain consumers of natural gas and gas service in the State of Louisiana. In February 2004, another suit was filed in state court in Calcasieu Parish, Louisiana against the Company seeking to recover alleged overcharges for gas or gas services allegedly provided by the Company to a purported class of certain consumers of natural gas and gas service without advance approval by the Louisiana Public Service Commission (LPSC). At the time of the filing of each of the Caddo and Calcasieu Parish cases, the plaintiffs in those cases filed petitions with the LPSC relating to the same alleged rate overcharges. The Caddo and Calcasieu Parish lawsuits have been stayed pending the resolution of the petitions filed with the LPSC. In August 2007, the LPSC issued an order approving a Stipulated Settlement in the review initiated by the plaintiffs in the Calcasieu Parish litigation. In the LPSC proceeding, the Company's gas purchases were reviewed back to 1971. The review concluded that the Company's gas costs were "reasonable and prudent," but the Company agreed to credit to jurisdictional customers approximately $920,000, including interest, related to certain off-system sales. A regulatory liability was established and the Company began refunding that amount to jurisdictional customers in September 2007. A similar review by the LPSC related to the Caddo Parish litigation was resolved without additional payment by the Company.

The range of relief sought by the plaintiffs in these cases includes injunctive and declaratory relief, restitution for the alleged overcharges, exemplary damages or trebling of actual damages, civil penalties and attorney's fees. The Company, CenterPoint Energy and their affiliates deny that they have overcharged any of their customers for natural gas and believe that the amounts recovered for purchased gas have been shown in the reviews described above to be in accordance with what is permitted by state and municipal regulatory authorities. The Company does not expect the outcome of these matters to have a material impact on its financial condition, results of operations or cash flows.

Storage Facility Litigation. In February 2007, an Oklahoma district court in Coal County, Oklahoma, granted a summary judgment against CEGT in a case, Deka Exploration, Inc. v. CenterPoint Energy, filed by holders of oil and gas leaseholds and some mineral interest owners in lands underlying CEGT's Chiles Dome Storage Facility. The dispute concerns "native gas" that may have been in the Wapanucka formation underlying the Chiles Dome facility when that facility was constructed in 1979 by a entity of the Company that was the predecessor in interest of CEGT. The court ruled that the plaintiffs own native gas underlying those lands, since neither CEGT nor its predecessors had condemned those ownership interests. The court rejected CEGT's contention that the claim should be barred by the statute of limitations, since the suit was filed over 25 years after the facility was constructed. The court also rejected CEGT's contention that the suit is an impermissible attack on the determinations the FERC and Oklahoma Corporation Commission made regarding the absence of native gas in the lands when the facility was constructed. The summary judgment ruling was only on the issue of liability, though the court did rule that CEGT has the burden of proving that any gas in the Wapanucka formation is gas that has been injected and is not native gas. Further hearings and orders of the court are required to specify the appropriate relief for the plaintiffs. CEGT plans to appeal through the Oklahoma court system any judgment that imposes liability on CEGT in this matter. The Company does not expect the outcome of this matter to have a material impact on its financial condition, results of operations or cash flows.

Environmental Matters

Hydrocarbon Contamination. CERC Corp. and certain of its subsidiaries were among the defendants in lawsuits filed beginning in August 2001 in Caddo Parish and Bossier Parish, Louisiana. The suits alleged 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 was 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 the Company. This facility was purportedly used for gathering natural gas from surrounding wells, separating liquid hydrocarbons from the natural gas for marketing, and transmission of natural gas for distribution.

In July 2007, pursuant to the terms of a previously agreed settlement in principle, the parties implemented the terms of their settlement and resolved this matter. Pursuant to the agreed terms, the Company entered into a cooperative agreement with the Louisiana Department of Environmental Quality (LDEQ), pursuant to which the

Company will work with the LDEQ to develop a remediation plan that could be implemented by the Company. Pursuant to the settlement terms, the Company made a settlement payment within the amounts previously reserved for this matter. The Company does not expect the costs associated with the resolution of this matter to have a material impact on its financial condition, results of operations or cash flows.

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

At December 31, 2007, the Company had accrued $14 million for remediation of these Minnesota sites and the estimated range of possible remediation costs for these sites was $4 million to $35 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. The Company has utilized an environmental expense tracker mechanism in its rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2007, the Company had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by the Company or may have been owned by one of its former affiliates. The Company has been named as a defendant in a lawsuit filed in the United States District Court, District of Maine, under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of the Company or its divisions. The Company has also been identified as a PRP by the State of Maine for a site that is the subject of the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including the Company, would have to contribute to that remediation. The Company is investigating details regarding the site and the range of environmental expenditures for potential remediation. However, the Company believes it is not liable as a former owner or operator of the site under the Comprehensive Environmental, Response, Compensation and Liability Act of 1980, as amended, and applicable state statutes, and is vigorously contesting the suit and its designation as a PRP.

Mercury Contamination. The Company's pipeline and distribution operations have in the past employed elemental mercury in measuring and regulating equipment. It is possible that small amounts of mercury may have been spilled in the course of normal maintenance and replacement operations and that these spills may have contaminated the immediate area with elemental mercury. The Company has found this type of contamination 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 is not known at this time, based on the Company's experience 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.

Asbestos. Some facilities formerly owned by the Company's predecessors have contained asbestos insulation and other asbestos-containing materials. The Company or its predecessor companies have been named, along with numerous others, as a defendant in lawsuits filed by certain individuals who claim injury due to exposure to asbestos during work at such formerly owned facilities. The Company anticipates that additional claims like those received may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, the Company intends to continue vigorously contesting claims that it does not consider to have merit and does not expect, based on its experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on the Company's financial condition, results of operations or cash flows.

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

Guaranties

Prior to CenterPoint Energy's distribution of its ownership in Reliant Energy, Inc. (RRI) to its shareholders, the Company had guaranteed certain contractual obligations of what became RRI's trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure the Company against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the Company's benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In February 2007, the Company and CenterPoint Energy made a formal demand on RRI in connection with one of the two remaining guaranties under procedures provided by the Master Separation Agreement, dated December 31, 2000, between Reliant Energy, Incorporated and RRI. That demand sought to resolve a disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. In December 2007, the Company, CenterPoint Energy and RRI amended the agreement relating to the security to be provided by RRI for these guaranties, pursuant to which the Company released the $29.3 million in letters of credit RRI had provided as security, and RRI agreed to provide cash or new letters of credit to secure the Company against exposure under the remaining guaranties as calculated under the new agreement if and to the extent changes in market conditions exposed the Company to a risk of loss on those guaranties.

The remaining exposure to the Company under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under those transportation contracts, which will be effective until 2018, was approximately $135 million as of December 31, 2007. RRI continues to meet its obligations under the contracts, and the Company believes current market conditions make those contracts valuable in the near term and that additional security is not needed at this time. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the contracts or if RRI should fail to provide security in the event market conditions change adversely, the Company's exposure to the counterparty under the guaranty could exceed the security provided by RRI.

9. Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair values of non-trading derivative assets and liabilities are equivalent to their carrying amounts in the Consolidated Balance Sheets at December 31, 2006 and 2007 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, 2006		December 31, 2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Financial liabilities:				
Long-term debt	$2,162	$2,311	$2,952	$3,079

10. Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions)			
Revenues	$2,690	$1,384	$1,400	$2,054
Operating income	200	65	69	138
Net income	97	23	13	74

	Year Ended December 31, 2007			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions)			
Revenues	$2,697	$1,566	$1,351	$2,162
Operating income	250	83	91	202
Net income	131	30	28	98

11. Reportable Business Segments

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

The Company's reportable business segments include the following: Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services 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. Competitive Natural Gas Sales and Services represents the Company's non-rate regulated gas sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. The Interstate Pipelines business segment includes the interstate natural gas pipeline operations. The Field Services business segment includes the natural gas gathering operations. Our Other Operations business segment includes unallocated corporate costs and inter-segment eliminations.

Long-lived assets include net property, plant and equipment, net goodwill and other intangibles and equity investments in unconsolidated subsidiaries. Inter-segment sales are eliminated in consolidation.

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

	Revenues from External Customers	Inter-segment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2005:						
Natural Gas Distribution	$ 3,837	$ 9	$ 152	$ 175	$ 4,612	$ 249
Competitive Natural Gas Sales and Services	3,884	245	2	60	1,849	12
Interstate Pipelines	255	131	36	165	2,400	118
Field Services	91	29	9	70	529	38
Other	3	7	(1)	(6)	743	—
Reconciling Eliminations	—	(421)	—	—	(1,832)	—
Consolidated	$ 8,070	$ —	$ 198	$ 464	$ 8,301	$ 417

	Revenues from External Customers	Inter-segment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2006:						
Natural Gas Distribution	$ 3,582	$ 11	$ 152	$ 124	$ 4,463	$ 187
Competitive Natural Gas Sales and Services	3,572	79	1	77	1,501	18
Interstate Pipelines	255	133	37	181	2,738	437
Field Services	119	31	10	89	608	65
Other	—	5	—	1	1,086	—
Reconciling Eliminations	—	(259)	—	—	(1,581)	—
Consolidated	$ 7,528	$ —	$ 200	$ 472	$ 8,815	$ 707
As of and for the year ended December 31, 2007:						
Natural Gas Distribution	$ 3,749	$ 10	$ 155	$ 218	$ 4,332	$ 191
Competitive Natural Gas Sales and Services	3,534	45	5	75	1,221	7
Interstate Pipelines	357	143	44	237	3,007	308
Field Services	136	39	11	99	669	74
Other	—	—	—	(3)	670	—
Reconciling Eliminations	—	(237)	—	—	(765)	—
Consolidated	$ 7,776	$ —	$ 215	$ 626	$ 9,134	$ 580

	Year Ended December 31,		
	2005	2006	2007
		(In millions)	
Revenues by Products and Services:			
Retail gas sales	$ 4,871	$ 4,546	$ 4,941
Wholesale gas sales	2,410	2,331	2,196
Gas transport	684	550	532
Energy products and services	105	101	107
Total	$ 8,070	$ 7,528	$ 7,776

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

None.

Item 9A(T). ***Controls and Procedures.***

Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2007 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 and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

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

Item 11. *Executive Compensation*

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

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

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

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

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 Accounting Fees and Services*

Aggregate fees billed to the Company during the fiscal years ending December 31, 2006 and 2007 by its principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31,	
	2006	2007
Audit fees	$ 1,108,600	$ 1,205,900
Audit-related fees	178,500	93,720
Total audit and audit-related fees	1,287,100	1,299,620
Tax fees	—	—
All other fees	—	—
Total fees	$ 1,287,100	$ 1,299,620

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

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PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) Financial Statements.

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2007.

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

I, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 71.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries (the "Company", an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and have issued our report thereon dated March 12, 2008 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company's adoption of a new accounting standard for conditional asset retirement obligations in 2005); such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company listed in the index at Item 15 (a)(2). This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated 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.

DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2008

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, 2007

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
Year Ended December 31, 2007:				
Accumulated provisions:				
Uncollectible accounts receivable	$32	$42	$37	$37
Deferred tax asset valuation allowance	22	(4)	—	18
Year Ended December 31, 2006:				
Accumulated provisions:				
Uncollectible accounts receivable	38	37	43	32
Deferred tax asset valuation allowance	21	1	—	22
Year Ended December 31, 2005:				
Accumulated provisions:				
Uncollectible accounts receivable	28	37	27	38
Deferred tax asset valuation allowance	20	1	—	21

(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, 2008.

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, 2008.

Signature	Title
/s/ DAVID M. MCCLANAHAN (David M. McClanahan)	Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)
/s/ GARY L. WHITLOCK (Gary L. Whitlock)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ WALTER L. FITZGERALD (Walter L. Fitzgerald)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2007

INDEX OF EXHIBITS

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

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2(a)(1)	—	Agreement and Plan of Merger among the Company, HL&P, HI Merger, Inc. and NorAm dated August 11, 1996	HI's Form 8-K dated August 11, 1996	1-7629	2
2(a)(2)	—	Amendment to Agreement and Plan of Merger among the Company, HL&P, HI Merger, Inc. and NorAm dated August 11,1996	Registration Statement on Form S-4	333-11329	2(c)
2(b)	—	Agreement and Plan of Merger dated December 29, 2000 merging Reliant Resources Merger Sub, Inc. with and into Reliant Energy Services, Inc.	Registration Statement on Form S-3	333-54526	2
3(a)(1)	—	Certificate of Incorporation of RERC Corp.	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(1)
3(a)(2)	—	Certificate of Merger merging former NorAm Energy Corp. with and into HI Merger, Inc. dated August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(2)
3(a)(3)	—	Certificate of Amendment changing the name to Reliant Energy Resources Corp.	Form 10-K for the year ended December 31, 1998	1-3187	3(a)(3)
3(a)(4)	—	Certificate of Amendment changing the name to CenterPoint Energy Resources Corp.	Form 10-Q for the quarter ended June 30, 2003	1-13265	3(a)(4)
3(b)	—	Bylaws of RERC Corp.	Form 10-K for the year ended December 31, 1997	1-3187	3(b)
4(a)(1)	—	Indenture, dated as of 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(a)(2)	—	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(b)(2)
4(b)(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

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(b)(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(b)(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(b)(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(b)(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(b)(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(b)(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(b)(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(b)(9)	—	Supplemental Indenture No. 8, dated as of December 28, 2005, providing for the issuance of CERC Corp.'s 6 1/2% Debentures due 2008	CNP's Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(b)(10)	—	Supplemental Indenture No. 9, dated as of May 18, 2006, providing for the issuance of CERC Corp.'s 6.15% Senior Notes due 2016	CNP's Form 10-Q for the quarter ended June 30, 2006	1-31447	4.7
4(b)(11)	—	Supplemental Indenture No. 10, dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CNP's Form 10-K for the year ended December 31, 2007	1-31447	4(f)(11)
4(b)(12)	—	Supplemental Indenture No. 11 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.125% Senior Notes due 2017	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.8
4(b)(13)	—	Supplemental Indenture No. 12 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.9
4(c)	—	$950,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CERC Corp., as Borrower, and the banks named therein	CNP's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.5

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

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10(a)	—	Service Agreement by and between Mississippi River Transmission Corporation and Laclede Gas Company dated August 22, 1989	NorAm's Form 10-K for the year ended December 31, 1989	1-13265	10.20
+12	—	Computation of Ratios of Earnings to Fixed Charges			
+23	—	Consent of Deloitte & Touche LLP			
+31.1	—	Rule 13a-14(a)/15d-14(a) Certification of David M. McClanahan			
+31.2	—	Rule 13a-14(a)/15d-14(a) Certification of Gary L. Whitlock			
+32.1	—	Section 1350 Certification of David M. McClanahan			
+32.2	—	Section 1350 Certification of Gary L. Whitlock			

Exhibit 12

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(millions of dollars)

	Year Ended December 31,				
	2003	2004	2005	2006	2007(1)
Net income	$ 129	$ 144	$ 193	$ 207	$ 287
Income taxes	59	87	116	116	173
Capitalized interest	(1)	(2)	(1)	(6)	(12)
	187	229	308	317	448
Fixed charges, as defined:					
Interest expense	179	178	176	167	187
Capitalized interest	1	2	1	6	12
Interest component of rentals charged to operating expense	9	10	11	17	14
Total fixed charges	189	190	188	190	213
Earnings, as defined	$ 376	$ 419	$ 496	$ 507	$ 661
Ratio of earnings to fixed charges	1.99	2.20	2.64	2.67	3.10

(1) Excluded from the computation of fixed charges is interest income of $2 million in 2007, which is included in income tax expense.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-145223 on Form S-3 of our reports dated March 12, 2008, relating to i) the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries (the “Company”) (such report expresses an unqualified opinion and includes an explanatory paragraph regarding the Company’s adoption of a new accounting standard related to conditional asset retirement obligations in 2005), and ii) the consolidated financial statement schedule, appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2007.

/s/ *DELOITTE & TOUCHE LLP*

Houston, Texas
March 12, 2008

Exhibit 31.1

CERTIFICATIONS

I, David M. McClanahan, certify that:

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

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) 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

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

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

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

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

Date: March 12, 2008

/s/ David M. McClanahan
David M. McClanahan
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Gary L. Whitlock, certify that:

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

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) 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

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

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

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

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

Date: March 12, 2008

/s/ Gary L. Whitlock
Gary L. Whitlock
Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2007 (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
President and Chief Executive Officer
March 12, 2008

Exhibit 32.2

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

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2007 (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, 2008