UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010

OR

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

FOR THE TRANSITION PERIOD FROM ______________________________ TO ________________________________

Commission File Number 1-13265

CenterPoint Energy Resources Corp.

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**76-0511406** *(I.R.S. Employer Identification No.)*
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
6.625% Senior Notes due 2037	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 £ No R

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 £ No R

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 R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes £ No £

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

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 Exchange Act).Yes £ No R

The aggregate market value of the common equity held by non-affiliates as of June 30, 2010: 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 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 Results of Operations to explain the reasons for material changes in the amount of revenue and expense items between 2008, 2009 and 2010.

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 and "Management's Narrative Analysis of Results of Operations — Certain Factors Affecting Future Earnings" in Item 7 of this report, which discussions are incorporated herein by reference.

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. From time to time, we consider the acquisition or the disposition of assets or businesses.

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 3.3 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 2010, approximately 42% of Gas Operations' total throughput was to residential customers and approximately 58% was to commercial and industrial customers.

The table below reflects the number of natural gas distribution customers by state as of December 31, 2010:

	Residential	Commercial/ Industrial	Total Customers
Arkansas	390,668	48,033	438,701
Louisiana	232,135	17,347	249,482
Minnesota	738,868	67,489	806,357
Mississippi	109,608	12,683	122,291
Oklahoma	93,388	10,620	104,008
Texas	1,451,666	90,719	1,542,385
Total Gas Operations	3,016,333	246,891	3,263,224

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 residential customers and natural gas sales and transportation for commercial and industrial customers is seasonal. In 2010, 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 2010, 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 2010 included BP Canada Energy Marketing Corp. (25.6% of supply volumes), ConocoPhillips Company (8.3%), Tenaska Marketing Ventures (6.8%), Kinder Morgan (6.3%), Oneok Energy Marketing Company (4.7%), and Cargill, Inc. (4.6%). Numerous other suppliers provided the remaining 43.7% 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 twelve years. Gas Operations anticipates that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

Gas Operations actively engages in commodity price stabilization pursuant to annual gas supply plans presented to and/or filed with each of its 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). Its 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 200,000 Dekatherms (DTH) per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf natural gas equivalent). It owns a liquefied natural gas plant facility with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf natural gas equivalent) and a production rate of 72,000 DTH 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.

Gas Operations has entered into various asset management agreements associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, these asset management agreements are contracts between Gas Operations and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, Gas Operations agreed to release transportation and storage capacity to other parties to manage gas storage, supply and delivery arrangements for Gas Operations and to use the released capacity for other purposes when it is not needed for Gas Operations. Gas Operations is compensated by the asset manager through payments made over the life of the agreements based in part on the results of the asset optimization. Gas Operations has received approval from the state regulatory commissions in Arkansas, Louisiana, Mississippi and Oklahoma to retain a share of the asset management agreement proceeds, although the percentage of payments to be retained by Gas Operations varies based on the jurisdiction, with the majority of the payments to benefit customers. The agreements have varying terms, the longest of which expires in 2016.

Assets

As of December 31, 2010, Gas Operations owned approximately 71,000 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 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 Pipelines, LLC (CEIP).

In 2010, CES marketed approximately 548 Bcf of natural gas, related energy services and transportation to approximately 12,200 customers (including approximately 7 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. The business has three operational divisions: wholesale, retail and intrastate pipelines, which are further described below.

Wholesale Division. 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 interstate and intrastate pipeline companies, and include gas utilities, large industrial customers and electric generation customers. This division includes the supply function for the procurement of natural gas and the management and optimization of transportation and storage assets for CES.

Retail Division. CES offers a variety of natural gas management services to smaller commercial and industrial customers, municipalities, educational institutions and hospitals, whose facilities are typically 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 17 states.

Intrastate Pipeline Division. CEIP provides transportation services to shippers and end-users and contracts out approximately 2.3 Bcf of storage at its Pierce Junction facility in Texas.

CES currently transports natural gas on over 40 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).

Our risk control policy, which is overseen by our 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, a $4 million maximum, are consistent with CES' 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. In 2010, CES' VaR averaged $0.7 million with a high of $1.7 million.

Assets

CEIP owns and operates approximately 233 miles of intrastate pipeline in Louisiana and Texas and holds storage facilities of approximately 2.3 Bcf in Texas under long-term leases. In addition, CES leases transportation capacity of approximately 0.9 Bcf per day on various interstate and intrastate pipelines and approximately 15.4 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, LLC (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, LLC (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 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 2010, approximately 16% of CEGT and MRT's total operating revenue was attributable to services provided to Gas Operations, an affiliate, and approximately 7% 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. The primary term of MRT's firm transportation and storage contracts with Laclede will expire in 2013. In May 2010, Gas Operations and CEGT reached an agreement to renew the contracts for terms extending through March 31, 2021. All applicable regulatory approvals have been received.

Carthage to Perryville. In February 2010, CEGT completed the expansion of the capacity of its Carthage to Perryville pipeline to approximately 1.9 Bcf per day. The 274 MMcf per day expansion includes new compressor units at two of CEGT's existing stations.

Southeast Supply Header, LLC. CenterPoint Southeastern Pipelines Holding, LLC, our wholly-owned subsidiary, owns a 50% interest in Southeast Supply Header, LLC (SESH). SESH owns a 1.0 Bcf per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama. The pipeline was placed into service in September 2008. The rates charged by SESH for interstate transportation services are regulated by the FERC. A wholly-owned, indirect subsidiary of Spectra Energy Corp. owns the remaining 50% interest in SESH.

Assets

Our interstate pipelines business currently owns and operates approximately 8,000 miles of natural gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. Our interstate pipeline business also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.3 Bcf and a combined working gas capacity of approximately 59 Bcf. Our interstate pipeline business 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. Our interstate pipeline business' 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, including electricity, coal and fuel oils. The primary competitive factor is price, but environmental considerations have grown in importance when consumers consider alternative forms of energy. 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, LLC. (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 2.0 Bcf per day of natural gas and, either directly or through its 50% interest in a joint venture, processes in excess of 260 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.

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

Magnolia Gathering System. In September 2009, CEFS entered into long-term agreements with an indirect wholly-owned subsidiary of Encana Corporation (Encana) and an indirect wholly-owned subsidiary of Royal Dutch Shell plc (Shell) to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Magnolia Gathering System) from Encana and Shell in northwest Louisiana. Each of the agreements includes acreage dedication and volume commitments for which CEFS has exclusive rights to gather Shell's and Encana's natural gas production.

During the year ended December 31, 2010, CEFS substantially completed the construction and initial expansion of the Magnolia Gathering System in order to permit the system to gather and treat up to 700 MMcf per day of natural gas, with only well connects remaining. As of December 31, 2010, CEFS had spent approximately $310 million on the original project scope, including the purchase of the original facilities and is in the second year of the 10-year 700 MMcf per day volume commitment made by Shell and Encana.

Pursuant to an expansion election made by Encana and Shell in March 2010, CEFS expanded the Magnolia Gathering System to increase its gathering and treating capacity by an additional 200 MMcf per day, increasing the aggregate capacity of the system to 900 MMcf per day. As of December 31, 2010, CEFS had spent approximately $47 million on the expansion. The expansion was completed and placed into service in February, 2011 at a total cost of approximately $52 million. The 200 MMcf per day incremental volume commitment made by Shell and Encana began contemporaneously with the completion of the expansion.

Under the long-term agreements, Encana or Shell may elect to require CEFS to expand the capacity of the Magnolia Gathering System by up to an additional 800 MMcf per day, bringing the total system capacity to 1.7 Bcf per day. CEFS estimates that the cost to expand the capacity of the Magnolia Gathering System by an additional 800 MMcf per day would be as much as $240 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Olympia Gathering System. In April 2010, CEFS entered into additional long-term agreements with Encana and Shell to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Olympia Gathering System) from Encana and Shell in northwest Louisiana.

Under the terms of the agreements, CEFS is expanding the Olympia Gathering System in order to permit the system to gather and treat up to 600 MMcf per day of natural gas. As of December 31, 2010, CEFS had spent approximately $340 million on the 600 MMcf per day project, including the purchase of the original facilities, and expects to incur up to an additional $85 million to complete this expansion. CEFS expects the full 600 MMcf per day of capacity to be in service in the first quarter of 2011. CEFS is in the first year of the 10-year 600 MMcf per day volume commitment made by Shell and Encana.

Under the long-term agreements, Encana and Shell may elect to require CEFS to expand the capacity of the Olympia Gathering System by up to an additional 520 MMcf per day, bringing the total system capacity to 1.1 Bcf per day. CEFS estimates that the cost to expand the capacity of the Olympia Gathering System by an additional 520 MMcf per day would be as much as $200 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Waskom Gas Processing Company. CenterPoint Energy Gas Processing Company, our wholly-owned, indirect subsidiary, owns a 50% general partnership interest in Waskom Gas Processing Company (Waskom). Waskom owns a natural gas processing plant and natural gas gathering assets located in East Texas. The plant is capable of processing approximately 285 MMcf per day of natural gas. The gathering assets are capable of gathering approximately 75 MMcf per day of natural gas.

Assets

Our field services business owns and operates approximately 3,800 miles of gathering lines and processing plants that collect, treat and process natural gas primarily from three regions 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 alternative forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price, but environmental considerations have grown in importance when consumers consider other forms of energy. 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 among forms of energy is affected by commodity pricing levels and influences the level of drilling activity and demand for our gathering operations.

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 14 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 interstate 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.

As a public utility holding company, under the Public Utility Holding Company Act of 2005, CenterPoint Energy and its subsidiaries, including us, are subject to reporting and accounting requirements and are required to maintain certain books and records and make them available for review by the FERC and state regulatory authorities in certain circumstances.

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 served by Gas Operations that have retained original jurisdiction.

Texas. In March 2008, Gas Operations filed a request to change its rates with the Railroad Commission and the 47 cities in its Texas Coast service territory, an area consisting of approximately 230,000 customers in cities and communities on the outskirts of Houston. In 2008, the Railroad Commission approved the implementation of rates increasing annual revenues by approximately $3.5 million. The approved rates were contested by a coalition of nine cities in an appeal to the 353rd district court in Travis County, Texas. In January 2010, that court reversed the Railroad Commission's order in part and remanded the matter to the Railroad Commission. In its final judgment, the court ruled that the Railroad Commission lacked authority to impose the approved cost of service adjustment mechanism in both those nine cities and in those areas in which the Railroad Commission has original jurisdiction. The Railroad Commission and Gas Operations have appealed the court's ruling on the cost of service adjustment mechanism to the 3rd Court of Appeals at Austin, Texas. Oral arguments were held in February 2011. The cost of service adjustment was initially effective for three successive years ending in calendar year 2010, but would automatically renew for successive three-year periods unless Gas Operations or the regulatory authority having original jurisdiction gave written notice to discontinue the adjustment mechanism by February 1, 2011. Certain cities that agreed to the initial implementation notified Gas Operations by February 1, 2011 of their desire to discontinue the adjustment mechanism. Gas Operations will continue the cost of service adjustments for the remaining areas.

In July 2009, Gas Operations filed a request to change its rates with the Railroad Commission and the 29 cities in its Houston service territory, consisting of approximately 940,000 customers in and around Houston. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Houston service territory. As finally submitted to the Railroad Commission and the cities, the proposed new rates would have resulted in an overall increase in annual revenue of $20.4 million, excluding carrying costs of approximately $2 million on its gas inventory, and would be subject to an annual cost of service adjustment. In January 2010, Gas Operations withdrew its request for an annual cost of service adjustment mechanism due to the uncertainty caused by the court's ruling in the above-mentioned Texas Coast appeal. In February 2010, the Railroad Commission issued its decision authorizing a revenue increase of $5.1 million annually, reflecting reduced depreciation rates as well as adjustments to pension and other employee benefits, accumulated deferred income taxes and other items. The Railroad Commission also approved a surcharge of $0.9 million per year to recover Hurricane Ike costs over three years. These rates went into effect in March 2010. Gas Operations and other parties are seeking judicial review of the Railroad Commission's decision in the 261st district court in Travis County, Texas.

In December 2010, Gas Operations filed a request to change its rates with the Railroad Commission and the 66 cities in its South Texas service territory, consisting of approximately 137,000 customers. The request seeks an increase in base revenues of approximately $6.5 million, based on an 11% return on equity and a capital structure of 56% equity and 44% debt. A decision from the Railroad Commission is anticipated in the summer of 2011.

In February 2011 the Railroad Commission approved a rule requiring evaluation of natural gas distribution systems and submission of a plan by August 2011 to address the risks identified. Each operator's risk-based program is to be developed in conjunction with the recently enacted federal regulations regarding integrity management for distribution system operators. The rule allows us to record a regulatory asset to account for amounts spent to comply with the rule and to accrue carrying costs. The determination of the reasonableness and necessity of any investment or expense will be determined in the next rate case. We do not anticipate compliance with this rule will cause a material increase in capital expenditures or operating costs.

The Texas legislature periodically reviews the performance of and the need for government agencies such as the Railroad Commission under the Texas Sunset law. In January 2011, the Sunset Commission established by the legislature issued its report on the Railroad Commission for consideration by the Texas legislature during its 2011 session. The recommendations by the Sunset Commission include replacing the three-member elected Railroad Commission with a single elected Commissioner, and moving hearings currently conducted at the Railroad Commission to the State Office of Administrative Hearings. The Sunset Commission also recommended changing the name of the Railroad Commission to the "Texas Oil and Gas Commission." We cannot predict what action, if any, the Texas legislature may take with respect to those recommendations.

Minnesota. In November 2008, Gas Operations filed a request with the Minnesota Public Utilities Commission (MPUC) to increase its rates for utility distribution service by $59.8 million annually. In addition, Gas Operations sought an adjustment mechanism that would annually adjust rates to reflect changes in use per customer. In December 2008, the MPUC accepted the case and approved an interim rate increase of $51.2 million, which became effective on January 2, 2009, subject to refund. In January 2010, the MPUC issued its decision authorizing a revenue increase of $40.8 million per year, with an overall rate of return of 8.09% (10.24% return on equity). The MPUC also authorized Gas Operations to implement a pilot program for residential and small volume commercial customers that is intended to decouple gas revenues from customers' natural gas usage. In July 2010, Gas Operations implemented the revised rates approved by the MPUC and in August 2010 completed the refund to customers of the difference between the amounts finally approved by the MPUC and interim amounts collected. In October 2010, the MPUC approved a request by Gas Operations to implement a rate adjustment to increase its conservation improvement plan (CIP) recovery rate from $9.7 million to $23.2 million annually. In addition, the MPUC approved a $1.4 million incentive based on Gas Operations' 2009 CIP program.

Department of Transportation

In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Act), which reauthorized the programs adopted under the Pipeline Safety Improvement Act of 2002 (2002 Act). These programs included several requirements related to ensuring pipeline safety, and a requirement to assess the integrity of pipeline transmission facilities in areas of high population concentration. Under the 2002 Act, remediation activities are to be performed over a 10-year period. Our pipeline subsidiaries are on schedule to comply with the timeframe mandated for completion of integrity assessment and remediation.

Pursuant to the 2006 Act, the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the Department of Transportation (DOT) issued regulations, effective February 12, 2010, requiring operators of gas distribution pipelines to develop and implement integrity management programs similar to those required for gas transmission pipelines, but tailored to reflect the differences in distribution pipelines. Operators of gas distribution systems must write and implement their integrity management programs by August 2, 2011. Our natural gas distribution companies are on schedule to meet this deadline.

Pursuant to the 2002 Act and the 2006 Act, PHMSA has adopted a number of rules concerning, among other things, distinguishing between gathering lines and transmission facilities, requiring certain design and construction features in new and replaced lines to reduce corrosion and requiring pipeline operators to amend existing written operations and maintenance procedures and operator qualification programs. PHMSA has also updated its reporting requirements for natural gas pipelines effective January 1, 2011.

We anticipate that compliance with these regulations and performance of the remediation activities by our interstate and intrastate pipelines and natural gas distribution companies will require increases in both capital expenditures and operating costs. The level of expenditures will depend upon several factors, including age, location and operating pressures of the facilities.

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 environmental conditions caused by our operations or attributable to former operations;
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations; and
- impacting the demand for our services by directly or indirectly affecting the use or price of natural gas, or the ability to extract natural gas in areas we serve in our interstate pipelines and field services businesses.

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” (GHGs) such as carbon dioxide (CO_2), a byproduct of burning fossil fuels, and methane, the principal component of the natural gas that we transport and deliver to customers. Legislation to regulate emissions of GHGs 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 industrial sources to meet stringent new standards that would require substantial reductions in carbon emissions. These regulations could be costly and difficult to implement. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues, such as the United Nations Climate Change Conference in Copenhagen in 2009. Also, the U.S. Environmental Protection Agency (EPA) has undertaken new efforts to collect information regarding GHG emissions and their effects. Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA proposed to expand its regulations relating to those emissions and has adopted rules imposing permitting and reporting obligations that we expect to be applicable to certain aspects of our operations. Specifically, the EPA adopted a final rule to address permitting of methane and other GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs. Additionally, the EPA has issued the “Mandatory Reporting of Greenhouse Gases Rule,” which establishes a new comprehensive scheme for reporting GHG emissions. In late 2010, the EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule, and will require facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year to report annual GHG emissions, with the first report due on March 31, 2012. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA.

It is too early to determine whether, or in what form, further regulatory action regarding GHG emissions will be adopted or what specific impacts a new regulatory action might have on us and our subsidiaries. Although it now appears unlikely that new legislation regarding GHGs will be adopted in the near term, action by the EPA to impose new regulations and standards regarding GHG emissions is underway and appears likely to result in new standards and regulatory requirements. 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 as a result of any regulatory action that would require installation of new control technologies or a modification of our operations or would have the effect of reducing the consumption of natural gas. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics, would be expected to beneficially affect us and our natural gas-related businesses. At this point in time, however, it would be speculative to try to quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on our businesses.

To the extent climate changes occur, our businesses may be adversely impacted, though we believe any such impacts are likely to occur very gradually and hence would be difficult to quantify with specificity. To the extent global climate change results in warmer temperatures in our service territories, financial results from our natural gas distribution businesses could be adversely affected through lower gas sales, and our gas transmission and field services businesses could experience lower revenues. Another possible climate change is more frequent and more severe weather events, such as hurricanes or tornadoes. Since many of our facilities are located along or near the Gulf Coast, increased or more severe hurricanes or tornadoes can increase our costs to repair damaged facilities and restore service to our customers. When we cannot deliver natural gas to customers or our customers cannot receive our services, our financial results can be impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs, or if higher rates resulting from our recovery of such costs result in reduced demand for our services, our future financial results may be adversely impacted.

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.

In 2010, the EPA adopted amendments to its regulations regarding maximum achievable control technology for stationary internal combustion engines (sometimes referred to as the RICE MACT rule) and continues to consider additional amendments. Compressors used by our Pipelines and Field Services segments are affected by these rules. Compliance with the current rules could require capital expenditures of $40 million to $50 million over the next 5 years. The estimated amount does not include costs to comply with new amendments which are expected to be proposed by the EPA for compliance by 2015. We estimate that compliance with these anticipated 2015 RICE MACT amendments as currently envisioned could require capital expenditures of $50 million to $75 million over the next 5 years. We believe, however, that our operations will not be materially adversely affected by such requirements.

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 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

Manufactured Gas Plant Sites. We and our predecessors operated manufactured gas plants (MGPs) 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, 2010, we 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 (PRPs), 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. In January 2010, as part of its Minnesota rate case decision, the MPUC eliminated the environmental expense tracker mechanism and ordered amounts previously collected from ratepayers and related carrying costs refunded to customers in 2010. Such refund was completed in August 2010. The MPUC provided for the inclusion in rates of approximately $285,000 annually to fund normal on-going remediation costs. We were not required to refund to customers the amount collected from insurance companies, $5.2 million at December 31, 2010, to be used to mitigate future environmental costs. The MPUC further gave assurance that any reasonable and prudent environmental clean-up costs we incur in the future will be rate-recoverable under normal regulatory principles and procedures. This provision had no impact on earnings.

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 a 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 would be required to determine if other potentially responsible parties, including us, would have to contribute to that remediation. In September 2009, the federal district court granted our motion for summary judgment in the proceeding. Although it is likely that the plaintiff will pursue an appeal from that dismissal, further action will not be taken until the district court disposes of claims against other defendants in the case. 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. We do not expect the ultimate outcome to have a material adverse impact on 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.

Groundwater Contamination Litigation. Predecessor entities of ours, along with several other entities, are defendants in litigation, *St. Michel Plantation, LLC, et al, v. White, et al*., pending in civil district court in Orleans Parish, Louisiana. In the lawsuit, the plaintiffs allege that their property in Terrebonne Parish, Louisiana suffered salt water contamination as a result of oil and gas drilling activities conducted by the defendants. Although a predecessor of ours held an interest in two oil and gas leases on a portion of the property at issue, neither it nor any other entities of ours drilled or conducted other oil and gas operations on those leases. In January 2009, we and the plaintiffs reached agreement on the terms of a settlement that, if ultimately approved by the Louisiana Department of Natural Resources, is expected to resolve this litigation. We do not expect the outcome of this litigation to have a material adverse impact 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, 2010, we had 4,725 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	3,586	1,362
Competitive Natural Gas Sales and Services	133	—
Interstate Pipelines	728	—
Field Services	278	—
Total	4,725	1,362

As of December 31, 2010, approximately 29% of our employees are subject to collective bargaining agreements. Collective bargaining agreements with two of our unions, the Gas Workers Union Local No. 340 and the International Brotherhood of Electrical Workers Local No. 949, that collectively represent approximately 14% of our employees are scheduled to expire in April and December 2011, respectively. We have a good relationship with these bargaining units and expect to negotiate new agreements in 2011.

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.

Our rates for Gas Operations are regulated by certain municipalities and state commissions, and for our interstate pipelines 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 alternate 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 and reduced volumes, 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, but recently, environmental considerations have grown in importance when consumers consider alternative forms of energy. 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. Additionally, any reduction in the volume of natural gas transported or stored 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 prices, which could affect the ability of our suppliers and customers to meet their obligations or otherwise adversely affect our liquidity and results of operations.

We are subject to risk associated with changes 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 (i) apply downward demand pressure on natural gas consumption in the areas in which we operate thereby resulting in decreased sales and transportation volumes and revenues and (ii) increase the risk that our suppliers or customers fail or are unable to meet their obligations. An increase in natural gas prices would also increase our working capital requirements by increasing the investment that must be made in order to maintain natural gas inventory levels. Additionally, a decrease in natural gas prices could increase the amount of collateral that we must provide under our hedging arrangements.

A decline in our credit rating could result in our having to provide collateral under our shipping or hedging arrangements or in order to purchase natural gas.

If our credit rating were to decline, we might be required to post cash collateral under our shipping or hedging arrangements or 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, our results of operations, financial condition and cash flows could be adversely affected.

The revenues and results of operations of our interstate pipelines and field services businesses are subject to fluctuations in the supply and price of natural gas and natural gas liquids and regulatory and other issues impacting our customers' production decisions.

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. The level of drilling and production activity in these regions is dependent on economic and business factors beyond our control. The primary factor affecting both the level of drilling activity and production volumes is natural gas pricing. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the regions served by our gathering and pipeline transportation systems and our natural gas treating and processing activities. A sustained decline could also lead producers to shut in production from their existing wells. Other factors that impact production decisions include the level of production costs relative to other available production, producers' access to needed capital and the cost of that capital, access to drilling rigs, the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Regulatory changes include the potential for more restrictive rules governing the use of hydraulic fracturing, a process used in the extraction of natural gas from shale reservoir formations, and the use of groundwater in that process. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves or to shut in production from existing reserves. 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 from these businesses are also affected by the prices of natural gas and natural gas liquids (NGLs). NGL prices generally fluctuate on a basis that correlates to fluctuations in crude oil prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. The markets and prices for natural gas, NGLs and crude oil depend upon factors beyond our control. These factors include supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors.

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 and gathering systems under construction, future pipeline, gathering and treating systems and related compression facilities may be significantly higher than we had planned.

Our subsidiaries have been recently involved in significant pipeline and gathering construction projects and, depending on available opportunities, may, from time to time, be involved in additional significant pipeline construction and gathering and treating system projects in the future. The construction of new pipelines, gathering and treating systems and related compression facilities may require the expenditure of significant amounts of capital, which may exceed our estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating 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 and its subsidiaries were subject prior to its repeal in the Energy Policy Act of 2005, 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, proposals have been put forth in some of the states in which we do business that have sought to expand the state regulatory frameworks to give state 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 business 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 conduct our utility operations, to finance our business and to provide cost-effective utility service. In addition, if more than one state adopts restrictions on 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, 2010, we had $3.5 billion of outstanding indebtedness on a consolidated basis. As of December 31, 2010, approximately $549 million principal amount of this debt is required to be paid through 2013. This amount excludes (1) $550 million principal amount of our 7.75% senior notes that were repaid at their maturity in February 2011 with proceeds from the issuance in January 2011 of $550 million principal amount of our 4.50% senior notes maturing subsequent to 2013, (2) approximately $489 million borrowed from the money pool and (3) approximately $397 million of 7.875% senior notes due in 2013 which were exchanged in January 2011 for 4.50% senior notes due 2021. Our future financing activities may be significantly affected by, among other things:

- general economic and capital market conditions;
- credit availability from financial institutions and other lenders;
- investor confidence in us and the markets in which we operate;
- maintenance of acceptable credit ratings by us and CenterPoint Energy;
- market expectations regarding our future earnings and cash flows;
- market perceptions of our and CenterPoint Energy's ability to access capital markets on reasonable terms;
- our exposure to GenOn Energy, Inc. (GenOn), (formerly known as RRI Energy, Inc., Reliant Energy, Inc. and Reliant Resources, Inc.) in connection with its indemnification obligations arising in connection with its separation from CenterPoint Energy;
- incremental collateral that may be required due to regulation of derivatives; and
- provisions of relevant tax and securities laws.

Our current credit ratings are discussed in "Management's Narrative Analysis of Results of Operations— Liquidity and Capital Resources — 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 creditworthiness and liquidity of our parent company and our affiliates could affect our creditworthiness and liquidity.

Our credit ratings and liquidity may be impacted by the creditworthiness and liquidity of our parent company and our affiliates. As of December 31, 2010, CenterPoint Energy and its subsidiaries other than us had approximately $514 million principal amount of debt required to be paid through 2013. This amount excludes principal repayments of approximately $920 million on transition and system restoration bonds and indexed debt securities obligations. If CenterPoint Energy were to experience a deterioration in its creditworthiness or liquidity, our creditworthiness and liquidity could be adversely affected. In addition, from time to time we and other affiliates invest or borrow funds in the money pool maintained by CenterPoint Energy. If CenterPoint Energy or the affiliates that borrow any funds that we might invest from time to time in the money pool were to experience a deterioration in their creditworthiness or liquidity, our creditworthiness, liquidity and the repayment of notes receivable from CenterPoint Energy and our affiliates participating in the money pool could be adversely impacted.

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.

Other than the financial covenants contained in our credit facility and receivables facility (described under "Liquidity and Capital Resources" in Item 7 of this report), which could have the practical effect of limiting the payment of dividends under certain circumstances, 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 could 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. As a result, we depend on distributions from our subsidiaries in order to meet our payment obligations. 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 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 environmental conditions caused by our operations, or attributable to former operations;
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations; and
- impacting the demand for our services by directly or indirectly affecting the use or price of natural gas, or the ability to extract natural gas in areas we serve in our interstate pipelines and field services businesses.

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.

Under some circumstances, we and CenterPoint Energy could incur liabilities associated with assets and businesses we and CenterPoint Energy no longer own. These assets and businesses were previously owned by Reliant Energy, Incorporated (Reliant Energy), a predecessor of CenterPoint Energy, directly or through subsidiaries, including us in some cases. Through a series of transactions, the assets and businesses were transferred to a predecessor of RRI Energy, Inc. (RRI).

In connection with the organization and capitalization of RRI, RRI and its subsidiaries assumed liabilities associated with various assets and businesses 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 GenOn 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.

In May 2009, RRI sold its Texas retail business to NRG Retail, a subsidiary of NRG Energy, Inc. In December 2010, Mirant Corporation merged with and became a wholly owned subsidiary of RRI (then known as RRI Energy, Inc.) and RRI changed its name from RRI Energy, Inc. to GenOn Energy, Inc. Neither the sale of the retail business nor the merger with Mirant Corporation alters GenOn’s contractual obligations to indemnify CenterPoint Energy and its subsidiaries, for certain liabilities, including their indemnification obligations regarding certain litigation, nor does it affect the terms of existing guaranty arrangements for certain GenOn gas transportation contracts.

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. When the companies separated, RRI agreed to secure us against obligations under the guaranties RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn) agreed to provide to us cash or letters of credit as security against our obligations under our remaining guaranties for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose us to a risk of loss on those guaranties based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $112 million as of December 31, 2010. Market conditions in the fourth quarter of 2010 required posting of security under the agreement, and GenOn posted approximately $7 million in collateral in December 2010. If GenOn should fail to perform the contractual obligations, we could have to honor our guarantee and, in such event, collateral provided as security may be insufficient to satisfy our obligations.

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

Reliant Energy and RRI (GenOn's predecessors) are named as defendants in a number of lawsuits arising out of sales of natural gas in California and other markets. Although these matters relate to the business and operations of GenOn, claims against Reliant Energy have been made on grounds that include liability of Reliant Energy as a controlling shareholder of GenOn's predecessor. We and CenterPoint Energy could incur liability if claims in one or more of these lawsuits were successfully asserted against us and CenterPoint Energy and indemnification from GenOn were determined to be unavailable or if GenOn were unable to satisfy indemnification obligations owed with respect to those claims.

The unsettled conditions in the global financial system may have impacts on our business, liquidity and financial condition that we currently cannot predict.

The continued unsettled conditions in the global financial system may have an impact on our business, liquidity and financial condition. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to access those markets, which could have an impact on our liquidity and flexibility to react to changing economic and business conditions. In addition, the cost of debt financing and the proceeds of equity financing may be materially adversely impacted by these market conditions. Defaults of lenders in our credit facilities, should they further occur, could adversely affect our liquidity. Capital market turmoil was reflected in significant reductions in equity market valuations in 2008, which significantly reduced the value of assets of CenterPoint Energy's pension plan. These reductions increased pension expense in 2009.

In addition to the credit and financial market issues, national and local recessionary conditions may impact our business in a variety of ways. These include, among other things, reduced customer usage, increased customer default rates and wide swings in commodity prices.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for our services.

Legislation to regulate emissions of GHGs 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. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues, such as the United Nations Climate Change Conference in Copenhagen in 2009. Also, the EPA has undertaken new efforts to collect information regarding GHG emissions and their effects. Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA proposed to expand its regulations relating to those emissions and has adopted rules imposing permitting and reporting obligations that we expect to be applicable to certain of our operations. The results of the permitting and reporting requirements could lead to further regulation of these GHGs by the EPA It is too early to determine whether, or in what form, further regulatory action regarding GHG emissions will be adopted or what specific impacts a new regulatory action might have on us and our subsidiaries. Action by the EPA to impose new regulations and standards regarding GHG emissions is underway and appears likely to result in new standards and regulatory requirements. 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 as a result of any regulatory action that would require installation of new control technologies or a modification of our operations or would have the effect of reducing the consumption of natural gas. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services.

Climate changes could result in more frequent severe weather events which could affect the results of operations of our businesses.

To the extent climate changes occur, our businesses may be adversely impacted, though we believe any such impacts are likely to occur very gradually and hence would be difficult to quantify with specificity. To the extent global climate change results in warmer temperatures in our service territories, financial results from our natural gas distribution businesses could be adversely affected through lower gas sales, and our gas transmission and field services businesses could experience lower revenues. Another possible climate change is more frequent and more severe weather events, such as hurricanes or tornadoes. Since many of our facilities are located along or near the Gulf Coast, increased or more severe hurricanes or tornadoes can increase our costs to repair damaged facilities and restore service to our customers. When we cannot deliver natural gas to customers or our customers cannot receive our services, our financial results can be impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs, or if higher rates resulting from our recovery of such costs result in reduced demand for our services, our future financial results may be adversely impacted.

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 — Our 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 — Our 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 — Our 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 — Our Business — Field Services — Assets" in Item 1 of this report, which information is incorporated herein by reference.

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 5 and 12(e) to our consolidated financial statements, which information is incorporated herein by reference.

Item 4. ***Removed and Reserved***

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 2008 and 2009, we paid dividends on our common stock of $100 million to Utility Holding, LLC. No dividends were paid to our parent in 2010.

Our revolving credit facility and our receivables facility limit our debt as a percentage of total capitalization to 65%. These covenants 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).

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 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. We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy).

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, economic conditions, 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 business segments are subject to rate regulation. A summary of our reportable business segments as of December 31, 2010 is set forth below:

Natural Gas Distribution

We own and operate our regulated natural gas distribution business (Gas Operations), which engages in intrastate natural gas sales to, and natural gas transportation for, approximately 3.3 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 23 states in the central and eastern regions of the United States.

Interstate Pipelines

Our interstate pipelines business owns and operates approximately 8,000 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 1.3 billion cubic feet (Bcf) and a combined working gas capacity of approximately 59 Bcf. It also owns a 50% interest in Southeast Supply Header, LLC (SESH). SESH owns a 1.0 Bcf per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama. Most storage operations are in north Louisiana and Oklahoma.

Field Services

Our field services business owns and operates approximately 3,800 miles of gathering pipelines and processing plants that collect, treat and process natural gas primarily from three regions located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas. It also owns a 50% general partnership interest in Waskom Gas Processing Company (Waskom). Waskom owns a natural gas processing plant and natural gas gathering assets located in East Texas. The plant is capable of processing approximately 285 million cubic feet (MMcf) per day of natural gas. The gathering assets are capable of gathering approximately 75 MMcf per day of natural gas.

Other Operations

Our other operations business segment includes unallocated corporate costs and inter-segment eliminations.

EXECUTIVE SUMMARY

Factors Influencing Our Business

We are an energy delivery company. The majority of our revenues are generated from the gathering, processing, transportation and sale of natural gas by our subsidiaries. To assess our financial performance, our management primarily monitors operating income and cash flows from our four business segments. Within these broader financial measures, we monitor margins, operation and maintenance expense, interest expense, capital spending and working capital requirements. In addition to these financial measures we also monitor a number of variables that management considers important to the operation of our business segments, including the number of customers, throughput, use per customer, commodity prices and heating degree days. We also monitor system reliability, safety factors and customer satisfaction to gauge our performance.

To the extent adverse economic conditions affect our suppliers and customers, results from our energy delivery businesses may suffer. Reduced demand and lower energy prices could lead to financial pressure on some of our customers who operate within the energy industry. Also, adverse economic conditions, coupled with concerns for protecting the environment, may cause consumers to use less energy or avoid expansions of their facilities, resulting in less demand for our services.

Performance of our Natural Gas Distribution business segment is significantly influenced by the number of customers and energy usage per customer. Weather conditions can have a significant impact on energy usage, and we compare our results on a weather adjusted basis. During 2009 and continuing into 2010, we saw evidence that customers are seeking to reduce their energy consumption, particularly during periods of high energy prices or in times of economic distress. That conservation can have adverse effects on our results. In many of our service areas, particularly in the Houston area and in Minnesota, we have benefited from customer growth that tends to mitigate the effects of reduced consumption. We anticipate that this growth will continue despite recent economic downturns, though that growth may be lower than we have recently experienced in these areas. In addition, the profitability of these businesses is influenced significantly by the regulatory treatment we receive from the various state and local regulators who set our gas distribution rates. In recent rate filings, we have sought rate mechanisms that help to decouple our results from the impacts of weather and conservation, but such rate mechanisms have not yet been approved in all jurisdictions. We plan to continue to pursue such decoupling mechanisms in our rate filings.

Our Field Services and Interstate Pipelines business segments are currently benefiting from their proximity to new natural gas producing regions in Texas, Arkansas, Oklahoma and Louisiana. Our Interstate Pipelines business segment benefited from new projects placed into service in 2009 on our Carthage to Perryville line, including a backhaul agreement due to expire in 2011. In our Field Services business segment, strong shale drilling activity has helped offset declines in traditional drilling activity. In monitoring performance of the segments, we focus on throughput of the pipelines and gathering systems, and in the case of Field Services, on well-connects.

Our Competitive Natural Gas Sales and Services business segment contracts with customers for transportation, storage and sales of natural gas on an unregulated basis. Its operations serve customers in the central and eastern regions of the United States. The segment benefits from favorable price differentials, either on a geographic basis or on a seasonal basis. While it utilizes financial derivatives to hedge its exposure to price movements, it does not engage in speculative or proprietary trading and maintains a low value at risk level, or VaR, to avoid significant financial exposures. Lower commodity prices and low price differentials during 2009 and 2010 adversely affected results for this business segment.

The nature of our businesses requires significant amounts of capital investment, and we rely on internally generated cash, borrowings under our credit facilities, inter-company borrowings proceeds from commercial paper and issuances of debt in the capital markets to satisfy these capital needs. We strive to maintain investment grade ratings for our securities in order to access the capital markets on terms we consider reasonable. Our goal is to improve our credit ratings over time. A reduction in our ratings generally would increase our borrowing costs for new issuances of debt, as well as borrowing costs under our existing revolving credit facility, and may prevent us from accessing the commercial paper markets. Disruptions in the financial markets, such as occurred in the last half of 2008 and continued during 2009, can also affect the availability of new capital on terms we consider attractive. In those circumstances, companies like us may not be able to obtain certain types of external financing or may be required to accept terms less favorable than they would otherwise accept. For that reason, we seek to maintain adequate liquidity for our businesses through the existing credit facility and prudent refinancing of existing debt.

As it did with many businesses, the sharp decline in stock market values during the latter part of 2008 had a significant adverse impact on the value of CenterPoint Energy's pension plan assets. That impact significantly increased the pension expense we recognized during 2009.

Significant Events

Long-Term Gas Gathering and Treating Agreements

Magnolia Gathering System. In September 2009, CenterPoint Energy Field Services, LLC (CEFS) entered into long-term agreements with an indirect wholly-owned subsidiary of Encana Corporation (Encana) and an indirect wholly-owned subsidiary of Royal Dutch Shell plc (Shell) to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Magnolia Gathering System) from Encana and Shell in northwest Louisiana. Each of the agreements includes acreage dedication and volume commitments for which CEFS has exclusive rights to gather Shell's and Encana's natural gas production.

During the year ended December 31, 2010, CEFS substantially completed the construction and initial expansion of the Magnolia Gathering System in order to permit the system to gather and treat up to 700 MMcf per day of natural gas, with only well connects remaining. As of December 31, 2010, CEFS had spent approximately $310 million on the original project scope, including the purchase of the original facilities and is in the second year of the 10-year 700 MMcf per day volume commitment made by Shell and Encana.

Pursuant to an expansion election made by Encana and Shell in March 2010, CEFS expanded the Magnolia Gathering System to increase its gathering and treating capacity by an additional 200 MMcf per day, increasing the aggregate capacity of the system to 900 MMcf per day. As of December 31, 2010, CEFS had spent approximately $47 million on the expansion. The expansion was completed and placed into service in February 2011 at a total cost of approximately $52 million. The 200 MMcf per day incremental 10-year volume commitment made by Shell and Encana began contemporaneously with the completion of the expansion.

Under the long-term agreements, Encana or Shell may elect to require CEFS to expand the capacity of the Magnolia Gathering System by up to an additional 800 MMcf per day, bringing the total system capacity to 1.7 Bcf per day. CEFS estimates that the cost to expand the capacity of the Magnolia Gathering System by an additional 800 MMcf per day would be as much as $240 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Olympia Gathering System. In April 2010, CEFS entered into additional long-term agreements with Encana and Shell to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Olympia Gathering System) from Encana and Shell in northwest Louisiana.

Under the terms of the agreements, CEFS is expanding the Olympia Gathering System in order to permit the system to gather and treat up to 600 MMcf per day of natural gas. As of December 31, 2010, CEFS had spent approximately $340 million on the 600 MMcf per day project, including the purchase of the original facilities, and expects to incur up to an additional $85 million to complete this expansion. CEFS expects the full 600 MMcf per day of capacity to be in service in the first quarter of 2011. CEFS is in the first year of the 10-year 600 MMcf per day volume commitment made by Shell and Encana.

Under the long-term agreements, Encana and Shell may elect to require CEFS to expand the capacity of the Olympia Gathering System by up to an additional 520 MMcf per day, bringing the total system capacity to 1.1 Bcf per day. CEFS estimates that the cost to expand the capacity of the Olympia Gathering System by an additional 520 MMcf per day would be as much as $200 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Debt Financing Transactions

In January 2010, we redeemed $45 million of our outstanding 6% convertible subordinated debentures due 2012 at 100% of the principal amount plus accrued and unpaid interest to the redemption date.

In January 2011, we issued $250 million aggregate principal amount of senior notes due 2021 with an interest rate of 4.50% and $300 million aggregate principal amount of senior notes due 2041 with an interest rate of 5.85%. The proceeds from the issuance of the notes were used for the repayment of $550 million of our 7.75% senior notes at their maturity in February 2011.

Also in January 2011, we issued an additional $343 million aggregate principal amount of 4.50% senior notes due 2021 and provided cash consideration of $114 million in exchange for $397 million aggregate principal amount of our 7.875% senior notes due 2013. The premium of $58 million paid on exchanged notes has been deferred and will be amortized to interest expense over the life of the 4.50% senior notes due 2021.

Financial Reform Legislation

On July 21, 2010 the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank), which makes substantial changes to regulatory oversight regarding banks and financial institutions. Many provisions of Dodd-Frank will also affect non-financial businesses such as those conducted by us and our subsidiaries. It is not possible at this time to predict the ultimate impacts this legislation may have on us and our subsidiaries since most of the provisions in the law will require extensive rulemaking by various regulatory agencies and authorities, including, among others, the Securities and Exchange Commission (SEC), the Commodities Futures Trading Commission (CFTC) and the New York Stock Exchange (NYSE). Nevertheless, in a number of areas, the resulting rules are expected to have direct or indirect impacts on our businesses.

Although Dodd-Frank includes significant new provisions regarding the regulation of derivatives, the impact of those requirements will not be known definitively until regulations have been adopted by the SEC and the CFTC.

Dodd-Frank also makes substantial changes to the regulatory oversight of the credit rating agencies that are typically engaged to rate our securities. It is presently unknown what effect implementation of these new provisions ultimately will have on the activities or costs associated with the credit rating process.

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 relating to the environment, including those related to global climate change;
- other state and federal legislative and regulatory actions or developments affecting various aspects of our business, including, among others, energy deregulation or re-regulation, pipeline safety, health care reform, financial reform and tax legislation;

- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;
- the timing and outcome of any audits, disputes and other proceedings related to taxes;
- problems with construction, implementation of necessary technology or other issues with respect to major capital projects that result in delays or in cost overruns that cannot be recouped in rates;
- industrial, commercial and residential growth in our service territory and changes in market demand, including the effects of energy efficiency measures and demographic patterns;
- the timing and extent of changes in commodity prices, particularly natural gas and natural gas liquids, and the effects of geographic and seasonal commodity price differentials;
- the timing and extent of changes in the supply of natural gas, including supplies available for gathering by our field services business and transporting by our interstate pipelines;
- weather variations and other natural phenomena;
- the impact of unplanned facility outages;
- 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;
- non-payment for our services due to financial distress of our customers;
- the ability of GenOn and its subsidiaries to satisfy their obligations to us, including indemnity obligations, or 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 pension and postretirement benefit plans;
- our potential business strategies, including restructurings, acquisitions or dispositions of assets or businesses, which we cannot assure will be completed or will have the anticipated benefits to us;
- acquisition and merger activities involving us or our competitors; 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, 2008, 2009 and 2010, 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,		
	2008	2009	2010
Revenues	$ 9,395	$ 6,257	$ 6,569
Expenses:			
Natural gas	7,466	4,371	4,574
Operation and maintenance	828	922	913
Depreciation and amortization	218	229	248
Taxes other than income taxes	166	166	167
Total	8,678	5,688	5,902
Operating Income	717	569	667
Interest and other finance charges	(206)	(213)	(208)
Equity in earnings of unconsolidated affiliates	51	15	29
Other income, net	9	5	(1)
Income Before Income Taxes	571	376	487
Income Tax Expense	(228)	(146)	(187)
Net Income	$ 343	$ 230	$ 300

2010 Compared to 2009. We reported net income of $300 million for 2010 compared to $230 million for 2009. The increase in net income of $70 million was primarily due to a $98 million increase in operating income from our business segments as discussed below and a $14 million increase in equity in earnings of unconsolidated affiliates, partially offset by a $41 million increase in income tax expense due to higher earnings.

Income Tax Expense. Our effective tax rate was 38.4% and 38.8% during 2010 and 2009, respectively. The 2010 effective tax rate included the effects of remeasuring accumulated deferred income taxes associated with the restructuring of certain subsidiaries in December 2010 (decrease in income tax expense of $24 million) as well as a change in tax law upon the enactment in March 2010 of the Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act of 2010 (increase in income tax expense of $19 million). In combination, these 2010 events did not have a material impact on our 2010 effective tax rate. The 2009 effective tax rate included a state income tax benefit of approximately $8 million, net of federal income tax effect, related to adjustments in prior years' state estimates. For more information, see Note 11 to our consolidated financial statements.

2009 Compared to 2008. We reported net income of $230 million for 2009 compared to $343 million for 2008. The decrease in net income of $113 million was primarily due to a $148 million decrease in operating income from our business segments as discussed below, a $36 million decrease in equity in earnings of unconsolidated affiliates and a $7 million increase in interest expense, partially offset by an $82 million decrease in income tax expense due to lower earnings.

Income Tax Expense. Our 2009 effective tax rate of 38.8% differed from the 2008 effective tax rate of 40.0% primarily due to a reduction in state income taxes related to adjustments in prior years' state estimates in 2009. For more information, see Note 11 to our consolidated financial statements.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (loss) (in millions) for each of our business segments for 2008, 2009 and 2010. Included in revenues are intersegment sales. We account for intersegment 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,		
	2008	2009	2010
Natural Gas Distribution	$ 215	$ 204	$ 231
Competitive Natural Gas Sales and Services	62	21	16
Interstate Pipelines	293	256	270
Field Services	147	94	151
Other Operations	—	(6)	(1)
Total Consolidated Operating Income	$ 717	$ 569	$ 667

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2008, 2009 and 2010 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 4,226	$ 3,384	$ 3,213
Expenses:			
Natural gas	3,124	2,251	2,049
Operation and maintenance	589	639	639
Depreciation and amortization	157	161	166
Taxes other than income taxes	141	129	128
Total expenses	4,011	3,180	2,982
Operating Income	$ 215	$ 204	$ 231
Throughput (in Bcf):			
Residential	175	173	177
Commercial and industrial	236	233	249
Total Throughput	411	406	426
Number of customers at end of period:			
Residential	2,987,222	3,002,114	3,016,333
Commercial and industrial	248,476	244,101	246,891
Total	3,235,698	3,246,215	3,263,224

2010 Compared to 2009. Our Natural Gas Distribution business segment reported operating income of $231 million for 2010 compared to $204 million for 2009. Operating income increased $27 million primarily as a result of revenue from base rate increases and annual rate adjustments ($24 million), lower pension and other benefits costs ($14 million), customer growth, higher throughput and increased other revenues ($8 million) and lower bad debt expense ($5 million). These were partially offset by higher labor costs ($7 million), higher contracts and services ($5 million) and other expenses ($7 million). Depreciation and amortization expense increased $5 million primarily due to higher plant balances.

2009 Compared to 2008. Our Natural Gas Distribution business segment reported operating income of $204 million for 2009 compared to $215 million for 2008. Operating income declined ($11 million) primarily as a result of increased pension expense ($37 million) and higher labor and other benefit costs ($16 million), partially offset by increased revenues from rate increases ($36 million) and lower bad debt expense ($15 million). Revenues related to both energy-efficiency costs and gross receipts taxes are substantially offset by the related expenses. Depreciation and amortization expense increased $4 million primarily due to higher plant balances. Taxes other than income taxes, net of the decrease in gross receipts taxes ($16 million), increased $4 million also primarily due to higher plant balances.

Competitive Natural Gas Sales and Services

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for 2008, 2009 and 2010 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 4,528	$ 2,230	$ 2,651
Expenses:			
Natural gas	4,423	2,165	2,591
Operation and maintenance	39	39	38
Depreciation and amortization	3	4	4
Taxes other than income taxes	1	1	2
Total expenses	4,466	2,209	2,635
Operating Income	$ 62	$ 21	$ 16
Throughput (in Bcf)	528	504	548
Number of customers at end of period	9,771	11,168	12,193

2010 Compared to 2009. Our Competitive Natural Gas Sales and Services business segment reported operating income of $16 million for 2010 compared to $21 million for 2009. The decrease in operating income of $5 million was primarily due to reduced basis spreads on pipeline transport opportunities and decreased seasonal storage spreads of $32 million as compared to last year. Offsetting this decrease to operating income is an increase in operating income of $27 million related to the favorable impact of the mark-to-market valuation for non-trading financial derivatives for 2010 of $4 million versus the unfavorable impact of $23 million for 2009. Additionally, a $6 million write-down of natural gas inventory to the lower of cost or market occurred in both 2009 and 2010.

2009 Compared to 2008. Our Competitive Natural Gas Sales and Services business segment reported operating income of $21 million for 2009 compared to $62 million for 2008. The decrease in operating income of $41 million was due to the unfavorable impact of the mark-to-market valuation for non-trading financial derivatives for 2009 of $23 million versus a favorable impact of $13 million for the same period in 2008. A further $28 million decrease in margin is attributable to reduced basis spreads on pipeline transport opportunities and an absence of summer storage spreads. These decreases in operating income were partially offset by a $6 million write-down of natural gas inventory to the lower of cost or market for 2009 compared to a $30 million write-down in the same period in 2008. Our Competitive Natural Gas Sales and Services business segment purchases and stores natural gas to meet certain future sales requirements and enters into derivative contracts to hedge the economic value of the future sales.

Interstate Pipelines

The following table provides summary data of our Interstate Pipelines business segment for 2008, 2009 and 2010 (in millions, except throughput data):

	Year Ended December 31, 2008	2009	2010
Revenues	$ 650	$ 598	$ 601
Expenses:			
Natural gas	155	97	93
Operation and maintenance	133	166	153
Depreciation and amortization	46	48	52
Taxes other than income taxes	23	31	33
Total expenses	357	342	331
Operating Income	$ 293	$ 256	$ 270
Equity in earnings of unconsolidated affiliates	$ 36	$ 7	$ 19
Transportation throughput (in Bcf)	1,538	1,592	1,693

2010 Compared to 2009. Our Interstate Pipeline business segment reported operating income of $270 million for 2010 compared to $256 million for 2009. Margins (revenues less natural gas costs) increased by $7 million primarily due to new contracts for the Phase IV Carthage to Perryville pipeline expansion ($42 million) and new power plant transportation contracts ($4 million), partially offset by reduced ancillary services, off-system and other transportation margins ($39 million). Lower operation and maintenance expenses ($13 million) were partially offset by increased depreciation and amortization expenses ($4 million) related to new assets and increased taxes other than income taxes ($2 million).

2009 Compared to 2008. Our Interstate Pipeline business segment reported operating income of $256 million for 2009 compared to $293 million for 2008. Margins increased $6 million primarily due to the Carthage to Perryville pipeline ($28 million) and new contracts with power generation customers ($20 million), partially offset by reduced other transportation margins and ancillary services ($42 million) primarily due to the decline in commodity prices from the significantly higher levels in 2008. Operations and maintenance expenses increased due to a gain on the sale of two storage development projects in 2008 ($18 million) and costs associated with incremental facilities ($12 million) and increased pension expenses ($9 million). These expenses were partially offset by a write-down associated with pipeline assets removed from service in the third quarter of 2008 ($7 million). Depreciation and amortization expenses increased $2 million and taxes other than income taxes increased by $8 million, $2 million of which was due to 2008 tax refunds.

Equity Earnings. In addition, this business segment recorded equity income of $36 million, $7 million and $19 million in the years ended December 31, 2008, 2009 and 2010, respectively, from its 50% interest in SESH, a jointly-owned pipeline. The 2008 year-end results include $33 million of pre-operating allowance for funds used during construction. The 2009 results include a non-cash pre-tax charge of $16 million to reflect SESH's decision to discontinue the use of guidance for accounting for regulated operations, which was partially offset by the receipt of a one-time payment related to the construction of the pipeline and a reduction in estimated property taxes, of which our 50% share was $5 million. Excluding the effect of these adjustments, equity earnings from normal operations was $3 million and $18 million in 2008 and 2009, respectively. These amounts are included in Equity in Earnings of Unconsolidated Affiliates under the Other Income (Expense) caption in the Statements of Consolidated Income.

Field Services

The following table provides summary data of our Field Services business segment for 2008, 2009 and 2010 (in millions, except throughput data):

	Year Ended December 31,		
	2008	2009	2010
Revenues	$ 252	$ 241	$ 338
Expenses:			
Natural gas	21	51	72
Operation and maintenance	69	77	85
Depreciation and amortization	12	15	25
Taxes other than income taxes	3	4	5
Total expenses	105	147	187
Operating Income	$ 147	$ 94	$ 151
Equity in earnings of unconsolidated affiliates	$ 15	$ 8	$ 10
Gathering throughput (in Bcf)	421	426	650

2010 Compared to 2009. Our Field Services business segment reported operating income of $151 million for 2010 compared to $94 million for 2009. Margins (revenues less natural gas costs) increased primarily due to new projects, including the Magnolia and Olympia Gathering Systems in the North Louisiana Haynesville Shale and core gathering services ($74 million), along with increased commodity prices ($2 million). Increases in operating expenses ($29 million) and depreciation ($10 million) associated with new projects were partially offset by a gain on the sale of non-strategic gathering assets in October 2010 ($21 million).

2009 Compared to 2008. Our Field Services business segment reported operating income of $94 million for 2009 compared to $147 million for 2008. Margins from new projects and core gathering services increased approximately $24 million for 2009 when compared to the same period in 2008 primarily due to continued development in the shale plays. This increase was offset primarily by the effect of a decline in commodity prices of approximately $54 million from the significantly higher prices experienced in 2008. Operating income for 2009 also included higher costs associated with incremental facilities ($4 million) and increased pension cost ($2 million). Operating income for 2008 benefited from a one-time gain ($11 million) related to a settlement and contract buyout of one of our customers and a gain on sale of assets ($6 million).

Equity Earnings. In addition, this business segment recorded equity income of $15 million, $8 million and $10 million for the years ended December 31, 2008, 2009 and 2010, respectively, from its 50% interest in Waskom. The increase is driven primarily by assets acquired in the first quarter of 2010 and higher natural gas liquid prices, partially offset by lower processing volumes. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption in the Statements of Consolidated Income.

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 AND CAPITAL RESOURCES

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, tax payments, working capital needs, various regulatory actions and appeals relating to such actions. Our principal anticipated cash requirements for 2011 include approximately $692 million of capital expenditures.

We expect that borrowings under our credit facility, advances under our receivables facility, proceeds from commercial paper, anticipated cash flows from operations and intercompany borrowings will be sufficient to meet our anticipated cash needs in 2011. Cash needs or discretionary financing or refinancing may result in the issuance of debt securities in the capital markets or the arrangement of additional credit facilities. Issuances of debt in the capital markets, funds raised in the commercial paper markets and additional credit facilities may not, however, be available to us on acceptable terms.

The following table sets forth our capital expenditures for 2010 and estimates of our capital expenditures for 2011 through 2015 (in millions):

	2010	2011	2012	2013	2014	2015
Natural Gas Distribution	$ 202	$ 263	$ 274	$ 285	$ 285	$ 285
Competitive Natural Gas Sales and Services	2	10	12	12	6	6
Interstate Pipelines	102	157	133	131	119	95
Field Services	668	262	135	125	59	60
Total	$ 974	$ 692	$ 554	$ 553	$ 469	$ 446

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

Contractual Obligations	Total	2011	2012-2013	2014-2015	2016 and thereafter
Long-term debt (1)	$ 2,925	$ —	$ 549	$ 160	$ 2,216
Interest payments — long-term debt(2)	1,893	186	325	221	1,161
Short-term borrowings	53	53	—	—	—
Operating leases(3)	57	15	18	9	15
Benefit obligations(4)	—	—	—	—	—
Purchase obligations(5)	1	1	—	—	—
Non-trading derivative liabilities	85	69	16	—	—
Other commodity commitments(6)	2,393	502	933	505	453
Income taxes(7)	—	—	—	—	—
Total contractual cash obligations	$ 7,407	$ 826	$ 1,841	$ 895	$ 3,845

(1) Maturities in 2011 exclude $550 million of our 7.75% senior notes and maturities in 2013 exclude $397 million of our 7.875% senior notes discussed in Note 10(b) to our consolidated financial statements and below under "— Debt Financing Transactions."

(2) 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, 2010. We typically expect to settle such interest payments with cash flows from operations and short-term borrowings.

(3) For a discussion of operating leases, please read Note 12(c) to our consolidated financial statements.

(4) We expect to contribute approximately $8 million to our postretirement benefits plan in 2011 to fund a portion of our obligations in accordance with rate orders or to fund pay-as-you-go costs associated with the plan.

(5) Represents capital commitments for material in connection with our Interstate Pipelines business segment.

(6) For a discussion of other commodity commitments, please read Note 12(a) to our consolidated financial statements.

(7) As of December 31, 2010, the liability for uncertain income tax positions was $11 million. However, due to the high degree of uncertainty regarding the timing of potential future cash flows associated with these liabilities, we are unable to make a reasonably reliable estimate of the amount and period in which any such liabilities might be paid.

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. When the companies separated, RRI agreed to secure us against obligations under the guaranties RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn) agreed to provide to us cash or letters of credit as security against our obligations under our remaining guaranties for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose us to a risk of loss on those guaranties based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $112 million as of December 31, 2010. Market conditions in the fourth quarter of 2010 required posting of security under the agreement, and GenOn posted approximately $7 million in collateral in December 2010. If GenOn should fail to perform the contractual obligations, we could have to honor its guarantee and, in such event, collateral provided as security may be insufficient to satisfy our obligations.

In May 2009, RRI sold its Texas retail business to NRG Retail, a subsidiary of NRG Energy, Inc. In December 2010, Mirant Corporation merged with and became a wholly owned subsidiary of RRI and RRI changed its name from RRI Energy, Inc. to GenOn Energy, Inc. Neither the sale of the retail business nor the merger with Mirant Corporation alters GenOn's contractual obligations to indemnify CenterPoint Energy and its subsidiaries for certain liabilities, including their indemnification obligations regarding certain litigation, nor does it affect the terms of existing guaranty arrangements for certain GenOn gas transportation contracts.

Debt Financing Transactions. In January 2010, we redeemed $45 million of our outstanding 6% convertible subordinated debentures due 2012 at 100% of the principal amount plus accrued and unpaid interest to the redemption date.

In January 2011, we issued $250 million aggregate principal amount of senior notes due 2021 with an interest rate of 4.50% and $300 million aggregate principal amount of senior notes due 2041 with an interest rate of 5.85%. The proceeds from the issuance of the notes were used for the repayment of $550 million of our 7.75% senior notes at their maturity in February 2011.

Also in January 2011, we issued an additional $343 million aggregate principal amount of 4.50% senior notes due 2021 and provided cash consideration of $114 million in exchange for $397 million aggregate principal amount of our 7.875% senior notes due 2013. The premium of $58 million paid on exchanged notes has been deferred and will be amortized to interest expense over the life of the 4.50% senior notes due 2021.

Credit and Receivables Facilities. In September 2010, we amended our 364-day receivables facility to extend the termination date to September 14, 2011. Availability under our receivables facility ranges from $160 million to $375 million, reflecting seasonal changes in receivables balances. As of December 31, 2009 and 2010, the facility size was $150 million and $160 million, respectively. As of both December 31, 2009 and 2010, there were no advances under the receivables facility.

As of February 15, 2011, we had the following facilities (in millions):

Date Executed	Type of Facility	Size of Facility	Amount Utilized at February 15, 2011	Termination Date
June 29, 2007	Revolver	$ 915	$ 248(1)	June 29, 2012
September 15, 2010	Receivables	375	—	September 14, 2011

(1) Represents commercial paper that is backstopped by CERC Corp.'s revolving credit facility.

CERC Corp.'s $915 million credit facility's first drawn cost is the London Interbank Offered Rate (LIBOR) plus 45 basis points based on our current credit ratings. The facility contains covenants, including a debt to total capitalization covenant, limiting total debt to 65% of our total capitalization.

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 the facility 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.

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

CERC Corp.'s $915 million credit facility backstops a $915 million commercial paper program under which we began issuing commercial paper in February 2008. As of December 31, 2010, we had $183 million of outstanding commercial paper. 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.

During 2010, we met substantially all of our liquidity requirements with borrowings from the money pool described below under "—Money Pool." During the fourth quarter of 2010, we also met a portion of our liquidity requirements with commercial paper proceeds. We currently expect that we may be required to access financing sources, in addition to money pool borrowings, in order to satisfy our liquidity requirements in 2011. These sources could include commercial paper proceeds or borrowings under our revolving credit or receivables facilities.

Securities Registered with the SEC. We have filed a shelf registration statement with the SEC registering an indeterminate principal amount of our senior debt securities.

Temporary Investments. As of February 15, 2011, 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 by CenterPoint Energy under its revolving credit facility or the sale by CenterPoint Energy of its commercial paper. At February 15, 2011, we had borrowings of $403 million from the money pool. The money pool may not provide sufficient funds to meet our cash needs.

Impact on Liquidity of a Downgrade in Credit Ratings. The interest on borrowings under our credit facilities is based on our credit rating. As of February 15, 2011, Moody's Investors Service, Inc. (Moody's), Standard & Poor's Rating Services (S&P), a division of The McGraw-Hill Companies, and Fitch, Inc. (Fitch) had assigned the following credit to our senior unsecured debt:

Moody's		S&P		Fitch	
Rating	**Outlook (1)**	**Rating**	**Outlook (2)**	**Rating**	**Outlook (3)**
Baa3	Positive	BBB	Stable	BBB	Stable

(1) A Moody's rating outlook is an opinion regarding the likely direction of a rating over the medium term.

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

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

We cannot assure you that the ratings set forth above 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 included for informational purposes and 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.

A decline in these credit ratings could increase borrowing costs under our $915 million credit facility. If our credit ratings had been downgraded one notch by each of the three principal credit rating agencies from the ratings that existed at December 31, 2010, the impact on the borrowing costs under our credit facility would have been immaterial. 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 and to access the commercial paper markets. 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.

We and our subsidiaries purchase natural gas from one of our suppliers under supply agreements that contain an aggregate credit threshold of $120 million based on CERC Corp.'s S&P senior unsecured long-term debt rating of BBB. Under these agreements, we may need to provide collateral if the aggregate threshold is exceeded. Upgrades and downgrades from this BBB rating will increase and decrease the aggregate credit threshold accordingly.

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, 2010, the amount posted as collateral aggregated approximately $107 million ($59 million of which is associated with price stabilization activities of our Natural Gas Distribution business segment). 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 up to the amount of its previously unsecured credit limit. We estimate that as of December 31, 2010, unsecured credit limits extended to CES by counterparties aggregate $248 million; however, utilized credit capacity was $79 million.

Pipeline tariffs and contracts typically provide that if the credit ratings of a shipper or the shipper's guarantor drop below a threshold level, which is generally investment grade ratings from both Moody's and S&P, cash or other collateral may be demanded from the shipper in an amount equal to the sum of three months' charges for pipeline services plus the unrecouped cost of any lateral built for such shipper. If the credit ratings of CERC Corp. decline below the applicable threshold levels, we might need to provide cash or other collateral of as much as $181 million as of December 31, 2010. The amount of collateral will depend on seasonal variations in transportation levels.

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. In addition, three outstanding series of CenterPoint Energy's senior notes, aggregating $750 million in principal amount as of December 31, 2010, provide that 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. A default by CenterPoint Energy would not trigger a default under our debt instruments or bank credit facilities.

Possible Acquisitions, Divestitures and Joint Ventures. From time to time, we consider the acquisition or the disposition of assets or businesses or possible joint ventures or other joint ownership arrangements with respect to assets or businesses. Any determination to take any action in this regard will be based on market conditions and opportunities existing at the time, and accordingly, the timing, size or success of any efforts and the associated potential capital commitments are unpredictable. We may seek to fund all or part of any such efforts with proceeds from debt issuances. Debt financing may not, however, be available to us at that time due to a variety of events, including, among others, maintenance of our credit ratings, industry conditions, general economic conditions, market conditions and market perceptions.

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 our weather hedging arrangements, and gas purchases, gas price and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments;

- 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 legislative or regulatory actions;
- incremental collateral, if any, that may be required due to regulation of derivatives;
- increased capital expenditures required for new gas pipeline or field services projects;
- the ability of our customers to fulfill their payment obligations to us;
- the ability of GenOn and its subsidiaries to satisfy their obligations in respect of GenOn's indemnity obligations to CenterPoint Energy and its subsidiaries or in connection with the contractual obligations to a third party pursuant to which we are their 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;
- restoration costs and revenue losses resulting from future natural disasters such as hurricanes and the timing of recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Item 1A of this report.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money. Our revolving credit 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.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Our Natural Gas Distribution business segment and portions of our Interstate Pipelines business segment apply this accounting guidance. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals. If events were to occur that would make the recovery of these assets and liabilities no longer probable, we would be required to write off or write down these regulatory assets and liabilities. At December 31, 2010, we had recorded regulatory assets of $68 million and regulatory liabilities of $572 million.

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 at least annually for goodwill as required by accounting guidance for goodwill and other intangible assets. No impairment of goodwill was indicated based on our annual analysis at July 1, 2010. 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.

Unbilled Energy 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 6(a) to our consolidated financial statements, we participate in CenterPoint Energy’s qualified and non-qualified pension plans covering substantially all employees. The expected pension cost for 2011 is $32 million, of which we expect $25 million to impact pre-tax earnings, based on an expected return on plan assets of 8.00% and a discount rate of 5.20% as of December 31, 2010. We recorded pension expense of $35 million for the year ended December 31, 2010. 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, natural gas liquids and other energy commodities.

- 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 commodity price risk 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, 2010, we had outstanding long-term debt, bank loans and borrowings from affiliates that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $432 million and $672 million at December 31, 2009 and 2010, respectively. If the floating interest rates were to increase by 10% from December 31, 2010 rates, our combined interest expense would increase by less than $1 million annually.

At December 31, 2009 and 2010, we had outstanding fixed-rate debt aggregating $2.8 billion and $2.7 billion in principal amount and having a fair value of $3.0 billion and $3.0 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 10 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $62 million if interest rates were to decline by 10% from their levels at December 31, 2010. 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, 2010, the recorded fair value of our non-trading energy derivatives was a net liability of $99 million (before collateral). The net liability consisted of a net liability of $123 million associated with price stabilization activities of our Natural Gas Distribution business segment and a net asset of $24 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. A decrease of 10% in the market prices of energy commodities from their December 31, 2010 levels would have increased the fair value of our non-trading energy derivatives net liability by $2 million. This increase in net liabilities consists of a $12 million increase to net liabilities associated with price stabilization activities of our Natural Gas Distribution business segment and a $10 million decrease to net liabilities related to our Competitive Natural Gas Sales and Services business segment.

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.

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, 2010 and 2009, 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, 2010. 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 at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 2011

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, 2010.

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our independent registered public accounting firm pursuant to 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 11, 2011

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

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2008	2009	2010
		(in millions)	
Revenues	$ 9,395	$ 6,257	$ 6,569
Expenses:			
Natural gas	7,466	4,371	4,574
Operation and maintenance	828	922	913
Depreciation and amortization	218	229	248
Taxes other than income taxes	166	166	167
Total	8,678	5,688	5,902
Operating Income	717	569	667
Other Income (Expense):			
Interest and other finance charges	(206)	(213)	(208)
Equity in earnings of unconsolidated affiliates	51	15	29
Other, net	9	5	(1)
Total	(146)	(193)	(180)
Income Before Income Taxes	571	376	487
Income tax expense	(228)	(146)	(187)
Net Income	$ 343	$ 230	$ 300

See Notes to Consolidated Financial Statements

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

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2008	2009	2010
		(in millions)	
Net income	$ 343	$ 230	$ 300
Other comprehensive income (loss), net of tax:			
Adjustment to pension and other postretirement plans (net of tax of $3, $3 and $1)	(13)	(2)	(1)
Reclassification of net deferred gain from cash flow hedges realized in net income (net of tax of $3, $-0- and $-0-)	(5)	—	—
Other comprehensive loss	(18)	(2)	(1)
Comprehensive income	$ 325	$ 228	$ 299

See Notes to Consolidated Financial Statements

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

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2010
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable, net	593	603
Accrued unbilled revenue	421	270
Accounts and notes receivable — affiliated companies	13	19
Inventory	258	304
Non-trading derivative assets	39	54
Taxes receivable	47	63
Deferred income tax assets	16	48
Prepaid expenses and other current assets	144	208
Total current assets	1,532	1,570
Property, Plant and Equipment, Net	5,875	6,636
Other Assets:		
Goodwill	1,696	1,696
Non-trading derivative assets	15	15
Investment in unconsolidated affiliates	463	468
Other	203	153
Total other assets	2,377	2,332
Total Assets	$ 9,784	$ 10,538
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ 55	$ 53
Current portion of long-term debt	44	—
Accounts payable	563	573
Accounts and notes payable — affiliated companies	472	541
Taxes accrued	67	73
Interest accrued	52	51
Customer deposits	70	76
Non-trading derivative liabilities	51	68
Other	282	255
Total current liabilities	1,656	1,690
Other Liabilities:		
Accumulated deferred income taxes, net	1,080	1,319
Non-trading derivative liabilities	42	16
Benefit obligations	113	100
Regulatory liabilities	539	572
Other	135	140
Total other liabilities	1,909	2,147
Long-Term Debt	2,742	2,925
	,	,
Commitments and Contingencies (Note 12)		
Stockholder's Equity	3,477	3,776
Total Liabilities And Stockholder's Equity	$ 9,784	$ 10,538

See Notes to 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,		
	2008	2009	2010
		(in millions)	
Cash Flows from Operating Activities:			
Net income	$ 343	$ 230	$ 300
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	218	229	248
Deferred income taxes	92	247	208
Amortization of deferred financing costs	9	9	9
Write-down of natural gas inventory	30	6	6
Equity in earnings of unconsolidated affiliates, net of distributions	(51)	(3)	13
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(66)	238	120
Accounts receivable/payable, affiliates	41	3	6
Inventory	(95)	231	(52)
Taxes receivable	—	(47)	(16)
Accounts payable	60	(160)	(35)
Fuel cost over (under) recovery	45	(5)	(9)
Interest and taxes accrued	(24)	(34)	5
Net non-trading derivative assets and liabilities	(19)	29	(5)
Margin deposits, net	(182)	116	7
Other current assets	(8)	46	(20)
Other current liabilities	17	57	(14)
Other assets	(3)	1	(7)
Other liabilities	(14)	(14)	(21)
Other, net	(33)	—	(21)
Net cash provided by operating activities	360	1,179	722
Cash Flows from Investing Activities:			
Capital expenditures	(532)	(690)	(917)
(Increase) decrease in notes receivable from unconsolidated affiliates	(175)	323	—
Investment in unconsolidated affiliates	(206)	(115)	(18)
Other, net	34	(3)	20
Net cash used in investing activities	(879)	(485)	(915)
Cash Flows from Financing Activities:			
Decrease in short-term borrowings, net	(79)	(98)	(2)
Revolving credit facility, net	776	(926)	—
Proceeds from commercial paper	—	—	183
Payments of long-term debt	(307)	(7)	(45)
Proceeds from long-term debt	300	—	—
Increase (decrease) in notes with affiliates, net	(79)	432	57
Dividends to parent	(100)	(100)	—
Debt issuance costs	(2)	—	—
Other, net	10	5	—
Net cash provided by (used in) financing activities	519	(694)	193
Net Decrease in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of the Year	1	1	1
Cash and Cash Equivalents at End of the Year	$ 1	$ 1	$ 1
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 210	$ 203	$ 191
Income taxes (refunds)	145	(31)	141
Non-cash transactions:			
Accounts payable related to capital expenditures	$ 52	$ 53	$ 98

See Notes to Consolidated Financial Statements

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

STATEMENTS OF CONSOLIDATED STOCKHOLDER'S EQUITY

	2008		2009		2010	
	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		2,406		2,416		2,416
Other		10		—		—
Balance, end of year		2,416		2,416		2,416
Retained Earnings						
Balance, beginning of year		692		935		1,065
Net income		343		230		300
Dividend to parent		(100)		(100)		—
Balance, end of year		935		1,065		1,365
Accumulated Other Comprehensive Loss						
Balance, end of year:						
Adjustment to pension and postretirement plans		(2)		(4)		(5)
Total accumulated other comprehensive loss, end of year		(2)		(4)		(5)
Total Stockholder's Equity		$ 3,349		$ 3,477		$ 3,776

See Notes to 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

CenterPoint Energy Resources Corp. (CERC Corp., and, together with its subsidiaries, CERC), owns and operates natural gas distribution systems in six states. Subsidiaries of CERC Corp. own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of CERC 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.

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

For a description of CERC's reportable business segments, see Note 14.

(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 CERC's consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. CERC uses the equity method of accounting for investments in entities in which CERC has an ownership interest between 20% and 50% and exercises significant influence. CERC’s investments in unconsolidated affiliates include a 50% ownership interest in Southeast Supply Header, LLC (SESH) which owns and operates a 274-mile interstate natural gas pipeline and a 50% interest in Waskom Gas Processing Company (Waskom), a Texas general partnership, which owns and operates a natural gas processing plant. During 2009, CERC invested $137 million in SESH and received a capital distribution of $23 million from SESH. During 2010, CERC invested $20 million in Waskom. Other investments, excluding marketable securities, are carried at cost.

(c) Revenues

CERC 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 and processing services are provided.

(d) Long-Lived Assets and Intangibles

CERC records property, plant and equipment at historical cost. CERC expenses repair and maintenance costs as incurred.

CERC 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, compared to the carrying value of the assets.

(e) Regulatory Assets and Liabilities

CERC applies the guidance for accounting for regulated operations to the Natural Gas Distribution business segment and to portions of the Interstate Pipelines business segment.

CERC's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2009 and 2010, these removal costs of $510 million and $545 million, respectively, are classified as regulatory liabilities in the Consolidated Balance Sheets. A portion of the amount of removal costs that relate to asset retirement obligations has been reclassified from a regulatory liability to an asset retirement liability in accordance with accounting guidance for conditional asset retirement obligations.

(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.

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

Interest and allowance for funds used during construction (AFUDC) are capitalized as a component of projects under construction and are amortized over the assets' estimated useful lives once the assets are placed in service. AFUDC represents the composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction for subsidiaries that apply the guidance for accounting for regulated operations. During 2008, 2009 and 2010, CERC capitalized interest and AFUDC of $5 million, $2 million and $7 million, respectively.

(h) Income Taxes

CERC is included in the consolidated income tax returns of CenterPoint Energy. CERC calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. CERC uses the asset and liability method of accounting for deferred income taxes in accordance with accounting guidance 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. CERC recognizes interest and penalties as a component of income tax expense.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $23 million and $25 million at December 31, 2009 and 2010, respectively. The provision for doubtful accounts in CERC's Statements of Consolidated Income for 2008, 2009 and 2010 was $53 million, $35 million and $30 million, 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 CERC'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 CERC's Natural Gas Distribution business segment are primarily valued at weighted average cost. During both 2009 and 2010, CERC recorded $6 million in write-downs of natural gas inventory to the lower of average cost or market.

	December 31,	
	2009	2010
	(in millions)	
Materials and supplies	$ 69	$ 93
Natural gas	189	211
Total inventory	$ 258	$ 304

(k) Derivative Instruments

CERC is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CERC 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 derivatives are recognized in CERC's Consolidated Balance Sheets at their fair value unless CERC elects the normal purchase and sales exemption for qualified physical transactions. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

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

CERC'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

CERC expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. CERC expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. CERC 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, CERC 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 June 2009, the Financial Accounting Standards Board (FASB) issued new accounting guidance on consolidation of variable interest entities (VIEs) that changes how a reporting entity determines a primary beneficiary that would consolidate the VIE from a quantitative risk and rewards approach to a qualitative approach based on which variable interest holder has the power to direct the economic performance related activities of the VIE as well as the obligation to absorb losses or right to receive benefits that could potentially be significant to the VIE. This new guidance requires the primary beneficiary assessment to be performed on an ongoing basis and also requires enhanced disclosures that will provide more transparency about a company’s involvement in a VIE. This new guidance was effective for a reporting entity’s first annual reporting period beginning after November 15, 2009. CERC’s adoption of this new guidance did not have a material impact on its financial position, results of operations or cash flows.

In January 2010, the FASB issued new accounting guidance to require additional fair value related disclosures It also clarified existing fair value disclosure guidance about the level of disaggregation and about inputs and valuation techniques. This new guidance was effective for the first reporting period beginning after December 15, 2009 except for certain disclosure requirements effective for the first reporting period beginning after December 15, 2010. The adoption of this new guidance did not have a material impact on CERC's financial position, results of operation or cash flows. See Note 9 for the required disclosures. CERC expects that the adoption of certain disclosure requirements effective in 2011 will not have a material impact on its financial position, results of operation or cash flows.

Management believes the impact of other recently issued standards, which are not yet effective, will not have a material impact on CERC's consolidated financial position, results of operations or cash flows upon adoption.

(o) Other Current Assets and Liabilities

Included in other current assets on the Consolidated Balance Sheets at December 31, 2009 and 2010 was $19 million and $23 million, respectively, of margin deposits and $80 million and $99 million, respectively of under-recovered gas cost. Included in other current liabilities on the Consolidated Balance Sheets at December 31, 2009 and 2010 was $70 million and $94 million, respectively, of over-recovered gas cost.

(3) Property, Plant and Equipment

(a) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2009	December 31, 2010
		(in millions)	
Natural Gas Distribution	31	$ 3,436	$ 3,642
Competitive Natural Gas Sales and Services	26	69	71
Interstate Pipelines	58	2,524	2,594
Field Services	46	931	1,583
Other property	13	27	49
Total		6,987	7,939
Accumulated depreciation and amortization:			
Natural Gas Distribution		825	954
Competitive Natural Gas Sales and Services		13	16
Interstate Pipelines		223	265
Field Services		27	43
Other property		24	25
Total accumulated depreciation and amortization		1,112	1,303
Property, plant and equipment, net		$ 5,875	$ 6,636

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense for 2008, 2009 and 2010:

	Year Ended December 31, 2008	2009	2010
		(in millions)	
Depreciation expense	$ 200	$ 211	$ 232
Amortization expense	18	18	16
Total depreciation and amortization expense	$ 218	$ 229	$ 248

(c) Asset Retirement Obligations

A reconciliation of the changes in the asset retirement obligation (ARO) liability is as follows (in millions):

	December 31,	
	2009	2010
Beginning balance	$ 46	$ 60
Accretion expense	5	4
Revisions in estimates of cash flows	9	(6)
Ending balance	$ 60	$ 58

The increase of $9 million in the ARO from the revision of estimate in 2009 is primarily attributable to the decrease in the credit-adjusted risk-free rate used to value the liability as of the end of the period. The decrease of $6 million in the ARO from the revision of the estimate in 2010 is primarily attributable to changes in the estimated lives of some of the assets underlying the liability. There were no material additions or settlements during the years ended December 31, 2009 and 2010.

(4) Goodwill

Goodwill by reportable business segment as of December 31, 2009 and 2010 is as follows (in millions):

Natural Gas Distribution	$ 746
Interstate Pipelines	579
Competitive Natural Gas Sales and Services	335
Field Services	25
Other Operations	11
Total	$ 1,696

CERC 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.

CERC performed the test at July 1, 2010, its annual impairment testing date, and determined that no impairment charge for goodwill was required.

(5) Regulatory Matters

(a) Regulatory Assets and Liabilities

The following is a list of regulatory assets/liabilities reflected on CERC's Consolidated Balance Sheets as of December 31, 2009 and 2010:

	December 31,	
	2009	2010
	(in millions)	
Regulatory assets in other long-term assets (1)	$ 61	$ 68
Regulatory liabilities	(539)	(572)
Net	$ (478)	$ (504)

(1) Regulatory assets that are not earning a return were not material at December 31, 2009 and 2010.

(b) Rate Proceedings

Texas. In March 2008, the natural gas distribution business of CERC (Gas Operations) filed a request to change its rates with the Railroad Commission of Texas (Railroad Commission) and the 47 cities in its Texas Coast service territory, an area consisting of approximately 230,000 customers in cities and communities on the outskirts of Houston. In 2008, the Railroad Commission approved the implementation of rates increasing annual revenues by approximately $3.5 million. The approved rates were contested by a coalition of nine cities in an appeal to the 353rd district court in Travis County, Texas. In January 2010, that court reversed the Railroad Commission's order in part and remanded the matter to the Railroad Commission. In its final judgment, the court ruled that the Railroad Commission lacked authority to impose the approved cost of service adjustment mechanism in both those nine cities and in those areas in which the Railroad Commission has original jurisdiction. The Railroad Commission and Gas Operations have appealed the court's ruling on the cost of service adjustment mechanism to the 3rd Court of Appeals at Austin, Texas. Oral arguments were held in February 2011. CERC does not expect the outcome of this matter to have a material adverse impact on its financial condition, results of operations or cash flows. The cost of service adjustment was initially effective for three successive years ending in calendar year 2010, but would automatically renew for successive three-year periods unless Gas Operations or the regulatory authority having original jurisdiction gave written notice to discontinue the adjustment mechanism by February 1, 2011. Certain cities that agreed to the initial implementation notified Gas Operations by February 1, 2011 of their desire to discontinue the adjustment mechanism. Gas Operations will continue the cost of service adjustments for the remaining areas.

In July 2009, Gas Operations filed a request to change its rates with the Railroad Commission and the 29 cities in its Houston service territory, consisting of approximately 940,000 customers in and around Houston. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Houston service territory. As finally submitted to the Railroad Commission and the cities, the proposed new rates would have resulted in an overall increase in annual revenue of $20.4 million, excluding carrying costs of approximately $2 million on its gas inventory, and would be subject to an annual cost of service adjustment. In January 2010, Gas Operations withdrew its request for an annual cost of service adjustment mechanism due to the uncertainty caused by the court's ruling in the above-mentioned Texas Coast appeal. In February 2010, the Railroad Commission issued its decision authorizing a revenue increase of $5.1 million annually, reflecting reduced depreciation rates as well as adjustments to pension and other employee benefits, accumulated deferred income taxes and other items. The Railroad Commission also approved a surcharge of $0.9 million per year to recover Hurricane Ike costs over three years. These rates went into effect in March 2010. Gas Operations and other parties are seeking judicial review of the Railroad Commission's decision in the 261st district court in Travis County, Texas.

In December 2010, Gas Operations filed a request to change its rates with the Railroad Commission and the 66 cities in its South Texas service territory, consisting of approximately 137,000 customers. The request seeks an increase in base revenues of approximately $6.5 million, based on an 11% return on equity and a capital structure of 56% equity and 44% debt. A decision from the Railroad Commission is anticipated in the summer of 2011.

Minnesota. In November 2008, Gas Operations filed a request with the Minnesota Public Utilities Commission (MPUC) to increase its rates for utility distribution service by $59.8 million annually. In addition, Gas Operations sought an adjustment mechanism that would annually adjust rates to reflect changes in use per customer. In December 2008, the MPUC accepted the case and approved an interim rate increase of $51.2 million, which became effective on January 2, 2009, subject to refund. In January 2010, the MPUC issued its decision authorizing a revenue increase of $40.8 million per year, with an overall rate of return of 8.09% (10.24% return on equity). The MPUC also authorized Gas Operations to implement a pilot program for residential and small volume commercial customers that is intended to decouple gas revenues from customers' natural gas usage. In July 2010, Gas Operations implemented the revised rates approved by the MPUC and in August 2010 completed the refund to customers of the difference between the amounts finally approved by the MPUC and interim amounts collected. In October 2010, the MPUC approved a request by Gas Operations to implement a rate adjustment to increase its conservation improvement plan (CIP) recovery rate from $9.7 million to $23.2 million annually. In addition, the MPUC approved a $1.4 million incentive based on Gas Operations' 2009 CIP program.

(c) Renewal of Affiliate Pipeline Transportation and Storage Service Agreements

In April 2010, Gas Operations and CenterPoint Energy Gas Transmission Company, LLC (CEGT) began negotiations to renew the pipeline transportation and storage service agreements that were scheduled to expire on March 31, 2012 for Arkansas, Louisiana, Oklahoma and Texas. In May 2010, Gas Operations and CEGT reached agreement to renew the contracts for terms extending through March 31, 2021. All applicable regulatory approvals have been received.

(d) Regulatory Accounting

CERC has a 50% ownership interest in SESH which owns and operates a 274-mile interstate natural gas pipeline. In 2009, SESH discontinued the use of guidance for accounting for regulated operations, which resulted in CERC recording its share of the effects of such write-offs of SESH's regulatory assets through non-cash pre-tax charges for the year ended December 31, 2009 of $16 million. These non-cash charges are reflected in equity in earnings of unconsolidated affiliates in the Statements of Consolidated Income. The related tax benefits of $6 million are reflected in the Income Tax Expense line in the Statements of Consolidated Income.

(6) Employee Benefit Plans

(a) Pension Plans

Substantially all of CERC'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 5% of eligible earnings, which increased from 4% effective January 1, 2009, and accrued interest. Prior to 1999, the pension plan accrued benefits based on years of service, final average pay and covered compensation. Certain employees participating in the plan as of December 31, 1998 automatically receive the greater of the accrued benefit calculated under the prior plan formula 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 CERC 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. CERC recognized pension income of $3 million and pension expense of $45 million and $34 million for the years ended December 31, 2008, 2009 and 2010, respectively.

In addition to the plan, CERC participates in CenterPoint Energy's non-qualified benefit restoration plans, which allow participants to receive the benefits to which they would have been entitled under CenterPoint Energy's non-contributory pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. The expense associated with the non-qualified pension plan was less than $1 million, $2 million and $1 million for the years ended December 31, 2008, 2009 and 2010, respectively.

(b) Savings Plan

CERC 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 50% of eligible compensation. CERC matches 100% of the first 6% of each employee's compensation contributed. The matching contributions are fully vested at all times. CenterPoint Energy allocates to CERC the savings plan benefit expense related to CERC's employees. Savings plan benefit expense was $18 million, $15 million and $16 million for each of the years ended December 31, 2008, 2009, and 2010, respectively.

(c) Postretirement Benefits

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

The net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2008	2009	2010
		(in millions)	
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on accumulated benefit obligation	7	8	7
Expected return on plan assets	(1)	(1)	(1)
Amortization of prior service cost	2	2	2
Net postretirement benefit cost	$ 9	$ 10	$ 9

CERC used the following assumptions to determine net postretirement benefit costs:

	Year Ended December 31,		
	2008	2009	2010
Discount rate	6.40%	6.90%	5.70%
Expected return on plan assets	4.50%	4.50%	4.50%

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

Following are reconciliations of CERC's beginning and ending balances of its postretirement benefit plan's benefit obligation, plan assets and funded status for 2009 and 2010. The measurement dates for plan assets and obligations were December 31, 2009 and 2010.

	Year Ended December 31,	
	2009	2010
	(in millions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 120	$ 121
Service cost	1	1
Interest cost	8	7
Benefits paid	(22)	(22)
Participant contributions	5	4
Actuarial loss	9	1
Accumulated benefit obligation, end of year	$ 121	$ 112
Change in Plan Assets		
Plan assets, beginning of year	$ 20	$ 21
Benefits paid	(22)	(22)
Employer contributions	16	18
Participant contributions	5	4
Actual investment return	2	1
Plan assets, end of year	$ 21	$ 22
Amounts Recognized in Balance Sheets		
Current liabilities-other	$ (8)	$ (7)
Other liabilities-benefit obligations	(92)	(83)
Net liability, end of year	$ (100)	$ (90)
Actuarial Assumptions		
Discount rate	5.70%	5.20%
Expected long-term return on assets	4.50%	4.50%
Healthcare cost trend rate assumed for the next year	7.50%	8.50%
Prescription cost trend rate assumed for the next year	8.00%	8.50%
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	2014	2017
Year that the prescription drug rate reaches the ultimate trend rate	2015	2017

The discount rate assumption was determined by matching the accrued cash flows of CenterPoint Energy's plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to thirty years.

The expected rate of return assumption was developed by a weighted-average return analysis of the targeted asset allocation of CenterPoint Energy's plans and the expected real return for each asset class, based on the long-term capital market assumptions, adjusted for investment fees and diversification effects, in addition to expected inflation.

For measurement purposes, healthcare and prescription costs are assumed to increase 8.50% during 2011, after which this rate decreases until reaching the ultimate trend rate of 5.50% in 2017, except for the 2013 rate which is expected to increase to 9.00% in anticipation of the healthcare exchanges being introduced to the market in 2014.

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

	Year Ended December 31,	
	2009	2010
	(in millions)	
Unrecognized actuarial loss	$ 21	$ 24
Unrecognized prior service cost	8	6
	29	30
Less deferred tax benefit (1)	(25)	(25)
Net amount recognized in accumulated other comprehensive loss	$ 4	$ 5

(1) CERC's postretirement benefit obligation is reduced by the impact of previously non-taxable government subsidies under the Medicare Prescription Drug Act. Because the subsidies were non-taxable, the temporary difference used in measuring the deferred tax impact was determined on the unrecognized losses excluding such subsidies.

The changes in plan assets and benefit obligations recognized in other comprehensive income during 2010 are as follows:

	Postretirement Benefits (in millions)
Net loss	$ 3
Amortization of prior service cost	(2)
Total recognized in other comprehensive income	$ 1

The total expense recognized in net periodic costs and other comprehensive income was $10 million for postretirement benefits for the year ended December 31, 2010.

The amounts in accumulated other comprehensive loss expected to be recognized as components of net periodic benefit cost during 2011 are as follows:

	Postretirement Benefits (in millions)
Unrecognized actuarial loss	$ 1
Unrecognized prior service cost	2
Amounts in other comprehensive income to be recognized as net periodic cost in 2011	$ 3

Assumed healthcare cost trend rates have a significant effect on the reported amounts for CERC'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	$ 4	$ (3)
Effect on the total of service and interest cost	—	—

In managing the investments associated with the postretirement benefit plan, CERC'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 that 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, CERC adopted and maintained the following asset allocation ranges for its postretirement benefit plan:

Domestic equity securities	15-25%
International equity securities	2-12%
Debt securities	68-78%
Cash	0-2%

The fair values of CERC's postretirement plan assets at December 31, 2009 and 2010, by asset category are as follows:

	Fair Value Measurements at December 31, 2009 (in millions)			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Mutual funds (1)	$ 21	$ 21	$ —	$ —
Total	$ 21	$ 21	$ —	$ —

(1) 95% of the amount invested in mutual funds was in fixed income securities and 5% was in U.S. equities.

	Fair Value Measurements at December 31, 2010 (in millions)			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Mutual funds (1)	$ 22	$ 22	$ —	$ —
Total	$ 22	$ 22	$ —	$ —

(1) 70% of the amount invested in mutual funds was in fixed income securities; 22% was in U.S. equities and 8% was in international equities.

CERC expects to contribute $8 million to its postretirement benefits plan in 2011. The following benefit payments are expected to be paid by the postretirement benefit plan:

	Postretirement Benefit Plan	
	Benefit Payments	Medicare Subsidy Receipts
	(in millions)	
2011	$ 11	$ (2)
2012	11	(2)
2013	12	(3)
2014	13	(3)
2015	13	(3)
2016-2020	70	(20)

(d) Postemployment Benefits

CERC participates in CenterPoint Energy's plan that 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). CERC recorded postemployment benefit expense of $1 million, $-0- and income of $1 million for the years ended December 31, 2008, 2009 and 2010, respectively. Amounts relating to postemployment benefits included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2009 and 2010, were $14 million and $11 million, respectively.

(e) Other Non-Qualified Plans

CERC 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 CERC. During 2008, 2009 and 2010, the benefit expense relating to these programs was less than $1 million each year. Amounts relating to deferred compensation plans included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2009 and 2010 were $2 million and $2 million, respectively.

(f) Other Employee Matters

As of December 31, 2010, approximately 29% of our employees are subject to collective bargaining agreements. Collective bargaining agreements with two of our unions, the Gas Workers Union Local No. 340 and the International Brotherhood of Electrical Workers Local No. 949, that collectively represent approximately 14% of our employees are scheduled to expire in April and December 2011, respectively.

(7) Related Party Transactions

CERC 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. CERC had money pool borrowings of $432 million and $489 million at December 31, 2009 and 2010, respectively, which are included in accounts and notes payable —affiliated companies in the Consolidated Balance Sheets. At December 31, 2010, CERC’s money pool borrowings had a weighted-average interest rate of 0.17%.

CERC had net interest expense related to affiliate borrowings of $1 million, less than $1 million and $2 million for the years ended December 31, 2008, 2009 and 2010, respectively.

CenterPoint Energy provides some corporate services to CERC. The costs of services have been charged directly to CERC 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 CERC not been an affiliate. Amounts charged to CERC for these services were $140 million, $154 million and $154 million for 2008, 2009 and 2010, respectively, and are included primarily in operation and maintenance expenses.

In 2008 and 2009, CERC paid dividends of $100 million to its parent. No dividends were paid to the parent in 2010.

(8) Derivative Instruments

CERC is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CERC 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

Derivative Instruments. CERC enters into certain derivative instruments to manage physical commodity price risks and does not engage in proprietary or speculative commodity trading. These financial instruments do not qualify or are not designated as cash flow or fair value hedges.

During the year ended December 31, 2008, CERC recorded increased natural gas revenues from unrealized net gains of $101 million and increased natural gas expense from unrealized net losses of $88 million, a net unrealized gain of $13 million. During the year ended December 31, 2009, CERC recorded decreased natural gas revenues from unrealized net losses of $80 million and decreased natural gas expense from unrealized net gains of $57 million, a net unrealized loss of $23 million. During the year ended December 31, 2010, CERC recorded increased natural gas revenues from unrealized net gains of $18 million and increased natural gas expense from unrealized net losses of $14 million, a net unrealized gain of $4 million.

Weather Hedges. CERC has weather normalization or other rate mechanisms that mitigate the impact of weather on its gas operations in Arkansas, Louisiana, Oklahoma and a portion of Texas. The remaining Gas Operations jurisdictions do not have such mechanisms. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of the gas operations in the remaining jurisdictions.

In 2008, 2009 and 2010, CERC entered into heating-degree day swaps to mitigate the effect of fluctuations from normal weather on its financial position and cash flows for the respective winter heating seasons. The swaps were based on ten-year normal weather. During the years ended December 31, 2008, 2009 and 2010, CERC recognized losses of $17 million, $6 million and $-0-, respectively, related to these swaps. The losses were substantially offset by increased revenues due to colder than normal weather. Weather hedge losses are included in revenues in the Statements of Consolidated Income.

(b) Derivative Fair Values and Income Statement Impacts

The following tables present information about CERC's derivative instruments and hedging activities. The first two tables provide a balance sheet overview of CERC's Derivative Assets and Liabilities as of December 31, 2009 and 2010, while the last table provides a breakdown of the related income statement impacts for the years ending December 31, 2009 and 2010.

Fair Value of Derivative Instruments

	December 31, 2009				
Total derivatives not designated as hedging instruments	**Balance Sheet Location**		**Derivative Assets Fair Value (2) (3)**		**Derivative Liabilities Fair Value (2) (3)**
			(in millions)		
Natural gas contracts (1)	Current Assets	$	46	$	(7)
Natural gas contracts (1)	Other Assets		16		(1)
Natural gas contracts (1)	Current Liabilities		20		(123)
Natural gas contracts (1)	Other Liabilities		1		(86)
Total		$	83	$	(217)

(1) Natural gas contracts are subject to master netting arrangements and are presented on a net basis in the Consolidated Balance Sheets. This netting causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets.

(2) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 674 billion cubic feet (Bcf) or a net 152 Bcf long position. Of the net long position, basis swaps constitute 71 Bcf and volumes associated with price stabilization activities of the Natural Gas Distribution business segment comprise 51 Bcf.

(3) The net of total non-trading derivative assets and liabilities is a $39 million liability as shown on CERC's Consolidated Balance Sheets, and is comprised of the natural gas contracts derivative assets and liabilities separately shown above offset by collateral netting of $95 million.

Fair Value of Derivative Instruments

	December 31, 2010				
Total derivatives not designated as hedging instruments	**Balance Sheet Location**		**Derivative Assets Fair Value (2) (3)**		**Derivative Liabilities Fair Value (2) (3)**
			(in millions)		
Natural gas contracts (1)	Current Assets	$	55	$	(1)
Natural gas contracts (1)	Other Assets		15		—
Natural gas contracts (1)	Current Liabilities		10		(143)
Natural gas contracts (1)	Other Liabilities		—		(35)
Total		$	80	$	(179)

(1) Natural gas contracts are subject to master netting arrangements and are presented on a net basis in the Consolidated Balance Sheets. This netting causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets.

(2) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 626 Bcf or a net 72 Bcf long position. Of the net long position, basis swaps constitute 63 Bcf and volumes associated with price stabilization activities of the Natural Gas Distribution business segment comprise 26 Bcf.

(3) The net of total non-trading derivative assets and liabilities is a $15 million liability as shown on CERC's Consolidated Balance Sheets, and is comprised of the natural gas contracts derivative assets and liabilities separately shown above offset by collateral netting of $84 million.

For CERC's price stabilization activities of the Natural Gas Distribution business segment, the settled costs of derivatives are ultimately recovered through purchased gas adjustments. Accordingly, the net unrealized gains and losses associated with these contracts are recorded as net regulatory assets. Realized and unrealized gains and losses on other derivatives are recognized in the Statements of Consolidated Income as revenue for retail sales derivative contracts and as natural gas expense for financial natural gas derivatives and non-retail related physical natural gas derivatives.

Income Statement Impact of Derivative Activity

Total derivatives not designated as hedging instruments	Income Statement Location	Year Ended December 31, 2009	Year Ended December 31, 2010
		(in millions)	
Natural gas contracts	Gains (Losses) in Revenue	$ 102	$ 90
Natural gas contracts (1)	Gains (Losses) in Expense: Natural Gas	(255)	(165)
Total		$ (153)	$ (75)

(1) The Gains (Losses) in Expense: Natural Gas includes $(181) million and $(115) million of costs in 2009 and 2010, respectively, associated with price stabilization activities of the Natural Gas Distribution business segment that will be ultimately recovered through purchased gas adjustments.

(c) Credit Risk Contingent Features

CERC enters into financial derivative contracts containing material adverse change provisions. These provisions could require CERC to post additional collateral if the Standard & Poor's Rating Services or Moody's Investors Service, Inc. credit ratings of CERC are downgraded. The total fair value of the derivative instruments that contain credit risk contingent features that are in a net liability position at December 31, 2009 and 2010 was $140 million and $107 million, respectively. The aggregate fair value of assets that are already posted as collateral was $65 million and $31 million, respectively, at December 31, 2009 and 2010. If all derivative contracts (in a net liability position) containing credit risk contingent features were triggered at December 31, 2009 and 2010, $75 million and $76 million, respectively, of additional assets would be required to be posted as collateral.

(d) Credit Quality of Counterparties

In addition to the risk associated with price movements, credit risk is also inherent in CERC'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 counterparties to the non-trading derivative assets of CERC as of December 31, 2009 and 2010 (in millions):

	December 31, 2009		December 31, 2010	
	Investment Grade(1)	Total	Investment Grade(1)	Total
Energy marketers	$ 6	$ 6	$ 5	$ 8
Financial institutions	2	4	1	1
Retail end users (2)	1	44	—	60
Total	$ 9	$ 54	$ 6	$ 69

(1) "Investment grade" is primarily determined using publicly available credit ratings and considering credit support (such as parent company guaranties) and collateral, which encompass cash and standby letters of credit. For unrated counterparties, CERC determines a synthetic credit rating by performing financial statement analysis and considering contractual rights and restrictions and collateral.

(2) Retail end users represent customers who have contracted to fix the price of a portion of their physical gas requirements for future periods.

(9) Fair Value Measurements

Assets and liabilities are recorded at fair value in the Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined in this guidance and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities, are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. The types of assets carried at Level 1 fair value generally are exchange-traded derivatives and equity securities.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. A market approach is utilized to value CERC's Level 2 assets or liabilities.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls has been determined based on the lowest level input that is significant to the fair value measurement in its entirety. Unobservable inputs reflect CERC's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. CERC develops these inputs based on the best information available, including CERC's own data. A market approach is utilized to value CERC's Level 3 assets or liabilities.

CERC determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period. For the year ended December 31, 2010, there were no significant transfers between levels.

The following tables present information about CERC's assets and liabilities (including derivatives that are presented net) measured at fair value on a recurring basis as of December 31, 2009 and 2010, and indicate the fair value hierarchy of the valuation techniques utilized by CERC to determine such fair value.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance as of December 31, 2009
			(in millions)		
Assets					
Corporate equities	$ 1	$ —	$ —	$ —	$ 1
Investments, including money market funds	11	—	—	—	11
Derivative assets	1	77	5	(29)	54
Total assets	$ 13	$ 77	$ 5	$ (29)	$ 66
Liabilities					
Derivative liabilities	$ 12	$ 194	$ 11	$ (124)	$ 93
Total liabilities	$ 12	$ 194	$ 11	$ (124)	$ 93

(1) Amounts represent the impact of legally enforceable master netting agreements that allow CERC to settle positive and negative positions and also include cash collateral of $95 million posted with the same counterparties.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments [1]	Balance as of December 31, 2010
			(in millions)		
Assets					
Corporate equities	$ 1	$ —	$ —	$ —	$ 1
Investments, including money market funds	11	—	—	—	11
Derivative assets	—	73	7	(11)	69
Total assets	$ 12	$ 73	$ 7	$ (11)	$ 81
Liabilities					
Derivative liabilities	$ 8	$ 167	$ 4	$ (95)	$ 84
Total liabilities	$ 8	$ 167	$ 4	$ (95)	$ 84

(1) Amounts represent the impact of legally enforceable master netting agreements that allow CERC to settle positive and negative positions and also include cash collateral of $84 million posted with the same counterparties.

The following tables present additional information about assets or liabilities, including derivatives that are measured at fair value on a recurring basis for which CERC has utilized Level 3 inputs to determine fair value:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Derivative assets and liabilities, net		
	Year Ended December 31,		
	2008	2009	2010
		(in millions)	
Beginning balance	$ (3)	$ (58)	$ (6)
Total unrealized gains or (losses):			
Included in earnings	(11)	(1)	4
Included in regulatory assets	(10)	(16)	(1)
Purchases, sales and other settlements, net:			
Included in earnings	6	3	(2)
Included in regulatory assets	(41)	66	8
Net transfers into Level 3	1	—	—
Ending balance	$ (58)	$ (6)	$ 3
The amount of total gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ 7	$ 1	$ 4

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. Non-trading derivative assets and liabilities are stated at fair value and are excluded from the table below. The fair value of each debt instrument is determined by multiplying the principal amount of each debt instrument by the market price.

	December 31, 2009		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(in millions)		
Financial liabilities:				
Long-term debt	$ 2,786	$ 2,969	$ 2,925	$ 3,158

(10) Short-term Borrowings and Long-term Debt

	December 31, 2009		December 31, 2010	
	Long-Term	Current(1)	Long-Term	Current(1)
	(in millions)			
Short-term borrowings:				
Inventory financing	$ —	$ 55	$ —	$ 53
Total short-term borrowings	—	55	—	53
Long-term debt:				
Convertible subordinated debentures 6.00% due 2012	—	44	—	—
Senior notes 5.95% to 7.875% due 2013 to 2037(2)	2,747	—	2,747	—
Commercial paper (3)	—	—	183	—
Unamortized discount and premium	(5)	—	(5)	—
Total long-term debt	2,742	44	2,925	—
Total debt	$ 2,742	$ 99	$ 2,925	$ 53

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

(2) $550 million senior notes due February 2011 are not reflected in the current portion of long-term debt as of December 31, 2010 because the notes were refinanced in January 2011.

(3) Classified as long-term debt because the termination date of the facility that backstops the commercial paper is more than one year from the date noted.

(a) Short-term Borrowings

Receivables Facility. On September 15, 2010, CERC amended its receivables facility to extend the termination date to September 14, 2011. Availability under CERC's 364-day receivables facility ranges from $160 million to $375 million, reflecting seasonal changes in receivables balances. At December 31, 2009 and 2010, the facility size was $150 million and $160 million, respectively. As of both December 31, 2009 and 2010, there were no advances under the receivables facility.

Inventory Financing. In October 2009, Gas Operations entered into asset management agreements associated with its utility distribution service in Arkansas, north Louisiana and Oklahoma that extend through March 31, 2012. Pursuant to the provisions of the agreements, Gas Operations sells natural gas and agrees to repurchase an equivalent amount of natural gas during the winter heating seasons at the same cost, plus a financing charge. These transactions are accounted for as a financing and they had an associated principal obligation of $55 million and $53 million as of December 31, 2009 and 2010, respectively.

(b) Long-term Debt

Convertible Subordinated Debentures. In January 2010, CERC Corp. redeemed $45 million of its outstanding 6% convertible subordinated debentures due 2012 at 100% of the principal amount plus accrued and unpaid interest to the redemption date.

CERC Corp. Senior Notes. In January 2011, CERC Corp. issued $250 million aggregate principal amount of senior notes due 2021 with an interest rate of 4.50% and $300 million aggregate principal amount of senior notes due 2041 with an interest rate of 5.85%. The proceeds from the issuance of the notes were used for the repayment of $550 million of CERC Corp.'s 7.75% senior notes at their maturity in February 2011. Accordingly, the $550 million senior notes due in February 2011 are reflected as long-term debt as of December 31, 2010.

CERC Corp. Exchange Offer. Also in January 2011, CERC Corp. issued an additional $343 million aggregate principal amount of 4.50% senior notes due 2021 and provided cash consideration of $114 million in exchange for $397 million aggregate principal amount of its 7.875% senior notes due 2013. The premium of $58 million paid on exchanged notes has been deferred and will be amortized to interest expense over the life of the 4.50% senior notes due 2021.

Revolving Credit Facility. As of December 31, 2009 and 2010, CERC Corp. had no outstanding borrowings under its $915 million credit facility. There was no outstanding commercial paper backstopped by CERC Corp.'s credit facility as of December 31, 2009 and $183 million in commercial paper outstanding as of December 31, 2010. CERC Corp. was in compliance with all debt covenants as of December 31, 2010.

CERC Corp.'s $915 million credit facility's first drawn cost is the London Interbank Offered Rate plus 45 basis points based on CERC Corp.'s current credit ratings. The facility contains a debt to total capitalization covenant, limiting debt to 65% of its total capitalization.

Maturities. CERC's consolidated maturities of long-term debt are $-0- in 2011, $183 million in 2012, $366 million in 2013, $160 million in 2014 and $-0- in 2015. Maturities in 2011 exclude $550 million of 7.75% senior notes and maturities in 2013 exclude $397 million of 7.875% senior notes, each refinanced as discussed above.

(11) Income Taxes

The components of the CERC's income tax expense were as follows:

	Year Ended December 31, 2008	2009	2010
		(in millions)	
Current income tax expense (benefit):			
Federal	$ 118	$ (107)	$ (38)
State	18	6	17
Total current expense (benefit)	136	(101)	(21)
Deferred income tax expense (benefit):			
Federal	60	226	234
State	32	21	(26)
Total deferred expense	92	247	208
Total income tax expense	$ 228	$ 146	$ 187

A reconciliation of the expected federal income tax expense using the federal statutory income tax rate to the actual income tax expense and resulting effective income tax rate is as follows:

	Year Ended December 31, 2008	2009	2010
		(in millions)	
Income before income taxes	$ 571	$ 376	$ 487
Federal statutory income tax rate	35%	35%	35%
Expected federal income tax expense	200	132	170
Increase (decrease) in tax expense resulting from:			
State income tax expense (benefit), net of federal income tax	32	18	(6)
Increase (decrease) in settled and uncertain income tax positions	(1)	(1)	5
Tax law change in deductibility of retiree health care costs	—	—	18
Other, net	(3)	(3)	—
Total	28	14	17
Total income tax expense	$ 228	$ 146	$ 187
Effective tax rate	40.0%	38.8%	38.4%

CERC recorded a non-cash, $19 million increase to income tax expense in 2010 as a result of a change in tax law upon the enactment in March 2010 of the Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act of 2010. The change in tax law, which becomes effective for tax years beginning after December 31, 2012, eliminates the tax deductibility of the portion of retiree health care costs that are reimbursed by Medicare Part D subsidies. Based upon the actuarially determined net present value of lost future retiree health care deductions related to the subsidies, CERC reduced its deferred tax asset by approximately $22 million in March 2010. The portion of the reduction that CERC believes will be recovered through the regulatory process, or approximately $2 million, was recorded as an adjustment to regulatory assets. The regulatory assets were also increased in March 2010 by approximately $1 million related to the recovery of CERC's income taxes. The remaining $19 million of the reduction in CERC's deferred tax asset was recorded as a charge to income tax expense in the first quarter of 2010.

In December 2010, certain subsidiaries of CERC were restructured in order to achieve a more tax-efficient reporting structure. As a result of the restructuring, CERC recorded a net reduction in income tax expense of approximately $24 million related to the remeasurement of accumulated deferred income taxes. The net reduction in income tax expense is comprised of a decrease in state income tax expense, net of federal income tax, totaling approximately $29 million and an increase in income tax expense of approximately $5 million related to uncertain income tax positions.

The state income tax expense of $18 million for 2009 included a benefit of approximately $8 million, net of federal income tax effect, related to adjustments in prior years' state estimates.

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

	December 31, 2009	December 31, 2010
	(in millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 9	$ 10
Deferred gas costs	7	33
Other	—	5
Total current deferred tax assets	16	48
Non-current:		
Employee benefits	83	55
Loss and credit carryforwards	12	19
Regulatory liabilities, net	12	—
Other	15	30
Total non-current deferred tax assets before valuation allowance	122	104
Valuation allowance	(5)	(3)
Total non-current deferred tax assets, net of valuation allowance	117	101
Total deferred tax assets, net of valuation allowance	133	149
Deferred tax liabilities:		
Non-current:		
Depreciation	$ 1,160	$ 1,397
Regulatory assets, net	—	14
Other	37	9
Total non-current deferred tax liabilities	1,197	1,420
Accumulated deferred income taxes, net	$ 1,064	$ 1,271

CERC is included in the consolidated income tax returns of CenterPoint Energy. CERC 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, 2010, CERC has approximately $312 million of state net operating loss carryforwards which expire in various years between 2011 and 2030. A valuation allowance has been established for approximately $4 million of the state net operating loss carryforwards that may not be realized. CERC has approximately $244 million of state capital loss carryforwards which expire in 2017 for which a valuation allowance has been established.

Uncertain Income Tax Positions. The following table reconciles the beginning and ending balance of CERC's unrecognized tax benefits:

	December 31, 2008	December 31, 2009	December 31, 2010
	(in millions)		
Balance, beginning of year	$ (11)	$ (12)	$ 6
Tax Positions related to prior years:			
Additions	—	18	—
Reductions	(1)	—	(2)
Tax Positions related to current year:			
Additions	—	2	7
Settlements	—	(2)	—
Balance, end of year	$ (12)	$ 6	$ 11

The net increase in the total amount of unrecognized tax benefits during 2010 is primarily related to the remeasurement of accumulated deferred income taxes associated with the restructuring of certain subsidiaries of CERC.

CERC had approximately $1 million and $5 million of unrecognized tax benefits that, if recognized, would reduce the effective income tax rate for 2008 and 2010, respectively. CERC had no unrecognized tax benefits that, if recognized, would reduce the effective income tax rate for 2009. CERC recognizes interest and penalties as a component of income tax expense. CERC recognized approximately $1 million of interest benefit, $1 million of interest benefit and $400 thousand of interest expense on uncertain income tax positions during 2008, 2009 and 2010, respectively. CERC accrued $4.9 million and $4.5 million of interest receivable on uncertain income tax positions at December 31, 2009 and 2010, respectively.

It is reasonably possible that the total amount of unrecognized tax benefits could decrease by as much as $1 million over the next 12 months primarily as a result of the anticipated resolution of CenterPoint Energy's administrative appeal associated with an the IRS examination described below. It is also reasonably possible that the total amount of unrecognized tax benefits could increase by as much as $17 million primarily as a result of the acceptance by the IRS of a refund claim related to the timing of a deduction for debt issuance costs.

Tax Audits and Settlements. CenterPoint Energy's consolidated federal income tax returns have been audited and settled through the 2005 tax year. As further described in the following paragraph, CenterPoint Energy has an administrative appeal pending before the IRS's Appeals Division related to tax years 2006 and 2007. In January 2011, the IRS commenced its examination of CenterPoint Energy's 2008 and 2009 consolidated federal income tax returns.

In July 2010, the IRS issued a report outlining proposed adjustments with respect to its examination of CenterPoint Energy's 2006 and 2007 federal income tax returns. The most significant adjustment proposed by the IRS that is associated with CERC relates to the capitalization into inventory of certain direct and indirect expenses totaling approximately $4 million. CenterPoint Energy has filed an administrative appeal with the IRS Appeals Division, but the proposed inventory adjustment was not contested. CERC has considered the adjustment's effects in its accrual for uncertain income tax positions as of December 31, 2010. Additionally, the capitalization of expenses into inventory is a temporary difference, and therefore, any increase or decrease in the balance of unrecognized tax benefits related thereto would not affect the effective tax rate.

(12) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to CERC'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 CERC's Consolidated Balance Sheets as of December 31, 2009 and 2010 as these contracts meet the 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, 2010, minimum payment obligations for natural gas supply commitments are approximately $502 million in 2011, $496 million in 2012, $437 million in 2013, $312 million in 2014, $193 million in 2015 and $453 million after 2015.

(b) Asset Management Agreements

Gas Operations has entered into asset management agreements associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, these asset management agreements are contracts between Gas Operations and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, Gas Operations agreed to release transportation and storage capacity to other parties to manage gas storage, supply and delivery arrangements for Gas Operations and to use the released capacity for other purposes when it is not needed for Gas Operations. Gas Operations is compensated by the asset manager through payments made over the life of the agreements based in part on the results of the asset optimization. Under the provisions of these asset management agreements, Gas Operations has an obligation to purchase its winter storage requirements from the asset manager. The agreements have varying terms, the longest of which expires in 2016.

(c) Lease Commitments

The following table sets forth information concerning CERC's obligations under non-cancelable long-term operating leases at December 31, 2010, which primarily consist of rental agreements for building space, data processing equipment and vehicles, including major work equipment (in millions):

2011	$	15
2012		11
2013		7
2014		5
2015		4
2016 and beyond		15
Total	$	57

Total rental expense for all operating leases was $41 million, $36 million and $76 million in 2008, 2009 and 2010, respectively.

(d) Capital Commitments

Magnolia Gathering System. In September 2009, CenterPoint Energy Field Services, LLC (CEFS) entered into long-term agreements with an indirect wholly-owned subsidiary of Encana Corporation (Encana) and an indirect wholly-owned subsidiary of Royal Dutch Shell plc (Shell) to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Magnolia Gathering System) from Encana and Shell in northwest Louisiana. Each of the agreements includes acreage dedication and volume commitments for which CEFS has exclusive rights to gather Shell's and Encana's natural gas production.

During the year ended December 31, 2010, CEFS substantially completed the construction and initial expansion of the Magnolia Gathering System in order to permit the system to gather and treat up to 700 million cubic feet (MMcf) per day of natural gas, with only well connects remaining. As of December 31, 2010, CEFS had spent approximately $310 million on the original project scope, including the purchase of the original facilities and is in the second year of the 10-year 700 MMcf per day volume commitment made by Shell and Encana.

Pursuant to an expansion election made by Encana and Shell in March 2010, CEFS expanded the Magnolia Gathering System to increase its gathering and treating capacity by an additional 200 MMcf per day, increasing the aggregate capacity of the system to 900 MMcf per day. As of December 31, 2010, CEFS had spent approximately $47 million on the expansion. The expansion was completed and placed into service in February 2011 at a total cost of approximately $52 million. The 200 MMcf per day incremental volume commitment made by Shell and Encana began contemporaneously with the completion of the expansion.

Under the long-term agreements, Encana or Shell may elect to require CEFS to expand the capacity of the Magnolia Gathering System by up to an additional 800 MMcf per day, bringing the total system capacity to 1.7 Bcf per day. CEFS estimates that the cost to expand the capacity of the Magnolia Gathering System by an additional 800 MMcf per day would be as much as $240 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

Olympia Gathering System. In April 2010, CEFS entered into additional long-term agreements with Encana and Shell to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana. Pursuant to these agreements, CEFS acquired jointly-owned gathering facilities (the Olympia Gathering System) from Encana and Shell in northwest Louisiana.

Under the terms of the agreements, CEFS is expanding the Olympia Gathering System in order to permit the system to gather and treat up to 600 MMcf per day of natural gas. As of December 31, 2010, CEFS had spent approximately $340 million on the 600 MMcf per day project, including the purchase of the original facilities, and expects to incur up to an additional $85 million to complete this expansion. CEFS expects the full 600 MMcf per day of capacity to be in service in the first quarter of 2011. CEFS is in the first year of the 10-year 600 MMcf per day volume commitment made by Shell and Encana.

Under the long-term agreements, Encana and Shell may elect to require CEFS to expand the capacity of the Olympia Gathering System by up to an additional 520 MMcf per day, bringing the total system capacity to 1.1 Bcf per day. CEFS estimates that the cost to expand the capacity of the Olympia Gathering System by an additional 520 MMcf per day would be as much as $200 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand the system's capacity.

(e) Legal, Environmental and Other Matters

Legal Matters

Gas Market Manipulation Cases. CenterPoint Energy or its predecessor, Reliant Energy, Incorporated (Reliant Energy), and certain of their former subsidiaries are named as defendants in certain lawsuits described below. Under a master separation agreement between CenterPoint Energy and a former subsidiary, RRI, CenterPoint Energy and its subsidiaries are entitled to be indemnified by RRI and its successors for any losses, including attorneys' fees and other costs, arising out of these lawsuits. In May 2009, RRI sold its Texas retail business to NRG Retail, a subsidiary of NRG Energy, Inc. and changed its name to RRI Energy, Inc. In December 2010, Mirant Corporation merged with and became a wholly owned subsidiary of RRI Energy, Inc., and RRI Energy, Inc. changed its name to GenOn Energy, Inc. (GenOn). Neither the sale of the retail business nor the merger with Mirant Corporation alters RRI's (now GenOn's) contractual obligations to indemnify CenterPoint Energy and its subsidiaries for certain liabilities, including their indemnification obligations regarding the gas market manipulation litigation, nor does it affect the terms of existing guaranty arrangements for certain GenOn gas transportation contracts discussed below.

A large number of lawsuits were filed against numerous gas market participants in a number of federal and western state courts in connection with the operation of the natural gas markets in 2000-2002. CenterPoint Energy's former affiliate, RRI, was a participant in gas trading in the California and Western markets. These lawsuits, many of which have been filed as class actions, allege violations of state and federal antitrust laws. Plaintiffs in these lawsuits are seeking a variety of forms of relief, including, among others, recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages, full consideration damages and attorneys' fees. CenterPoint Energy and/or Reliant Energy were named in approximately 30 of these lawsuits, which were instituted between 2003 and 2009. CenterPoint Energy and its affiliates have been released or dismissed from all but two of such cases. CenterPoint Energy Services, Inc. (CES), a subsidiary of CERC Corp., is a defendant in a case now pending in federal court in Nevada alleging a conspiracy to inflate Wisconsin natural gas prices in 2000-2002. Additionally, CenterPoint Energy was a defendant in a lawsuit filed in state court in Nevada that was dismissed in 2007, but in March 2010 the plaintiffs appealed the dismissal to the Nevada Supreme Court. CenterPoint Energy believes that neither it nor CES is a proper defendant in these remaining cases and will continue to pursue dismissal from those cases. CenterPoint Energy does not expect the ultimate outcome of these remaining matters to have a material impact on its financial condition, results of operations or cash flows.

Natural Gas Measurement Lawsuits. 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. In September 2009, the district court in Stevens County, Kansas, denied plaintiffs' request for class certification of their case and, in March 2010, denied the plaintiffs' request for reconsideration of that order. The time for seeking further review of the district court's decision has now passed.

CERC believes that there has been no systematic mismeasurement of gas and that these lawsuits are without merit. CERC does not expect the ultimate outcome of the lawsuits to have a material impact on its financial condition, results of operations or cash flows.

Environmental Matters

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

At December 31, 2010, CERC 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 (PRPs), if any, and the remediation methods used. CERC has utilized an environmental expense tracker mechanism in its rates in Minnesota to recover estimated costs in excess of insurance recovery. In January 2010, as part of its Minnesota rate case decision, the MPUC eliminated the environmental expense tracker mechanism and ordered amounts previously collected from ratepayers and related carrying costs refunded to customers in 2010. Such refund was completed in August 2010. The MPUC provided for the inclusion in rates of approximately $285,000 annually to fund normal on-going remediation costs. CERC was not required to refund to customers the amount collected from insurance companies, $5.2 million at December 31, 2010, to be used to mitigate future environmental costs. The MPUC further gave assurance that any reasonable and prudent environmental clean-up costs CERC incurs in the future will be rate-recoverable under normal regulatory principles and procedures. This provision had no impact on earnings.

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 CERC or may have been owned by one of its former affiliates. CERC 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 CERC or its divisions. CERC has also been identified as a PRP by the State of Maine for a site that is a 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 would be required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. In September 2009, the federal district court granted CERC's motion for summary judgment in the proceeding. Although it is likely that the plaintiff will pursue an appeal from that dismissal, further action will not be taken until the district court disposes of claims against other defendants in the case. CERC 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. CERC does not expect the ultimate outcome to have a material adverse impact on its financial condition, results of operations or cash flows.

Asbestos. Some facilities formerly owned by CERC's predecessors have contained asbestos insulation and other asbestos-containing materials. CERC 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. CERC anticipates that additional claims like those received may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, CERC 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 its financial condition, results of operations or cash flows.

Groundwater Contamination Litigation. Predecessor entities of CERC, along with several other entities, are defendants in litigation, *St. Michel Plantation, LLC, et al, v. White, et al*., pending in civil district court in Orleans Parish, Louisiana. In the lawsuit, the plaintiffs allege that their property in Terrebonne Parish, Louisiana suffered salt water contamination as a result of oil and gas drilling activities conducted by the defendants. Although a predecessor of CERC held an interest in two oil and gas leases on a portion of the property at issue, neither it nor any other CERC entities drilled or conducted other oil and gas operations on those leases. In January 2009, CERC and the plaintiffs reached agreement on the terms of a settlement that, if ultimately approved by the Louisiana Department of Natural Resources, is expected to resolve this litigation. CERC does not expect the outcome of this litigation to have a material adverse impact on its financial condition, results of operations or cash flows.

Other Environmental. From time to time CERC 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, CERC 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, CERC does not expect, based on its experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on its financial condition, results of operations or cash flows.

Other Proceedings

CERC 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. CERC regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. CERC does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(f) Guaranties

Prior to the distribution of CenterPoint Energy's ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI's trading subsidiary. When the companies separated, RRI agreed to secure CERC against obligations under the guaranties RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn) agreed to provide to CERC cash or letters of credit as security against CERC's obligations under its remaining guaranties for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose CERC to a risk of loss on those guaranties based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately \$112 million as of December 31, 2010. Market conditions in the fourth quarter of 2010 required posting of security under the agreement, and GenOn posted approximately \$7 million in collateral in December 2010. If GenOn should fail to perform the contractual obligations, CERC could have to honor its guarantee and, in such event, collateral provided as security may be insufficient to satisfy CERC's obligations.

(13) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in millions)			
Revenues	$ 2,351	$ 1,116	$ 965	$ 1,825
Operating income	214	89	64	202
Net income	95	34	5	96

	Year Ended December 31, 2010			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter (1)
	(in millions)			
Revenues	$ 2,538	$ 1,191	$ 1,250	$ 1,590
Operating income	248	101	111	207
Net income	106	33	42	119

(1) During the fourth quarter of 2010, CERC recorded a $21 million gain on the sale of non-strategic gathering assets by its Field Services business segment. CERC also recorded a $24 million decrease in income tax expense related to the effects of re-measuring accumulated deferred income taxes associated with the restructuring of certain subsidiaries.

(14) Reportable Business Segments

Because CERC is an indirect wholly owned subsidiary of CenterPoint Energy, CERC'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. CERC uses operating income as the measure of profit or loss for its business segments.

CERC'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 CenterPoint Energy's non-rate regulated gas sales and services operations, which consist of the following 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 non-rate regulated natural gas gathering, processing and treating 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. Intersegment sales are eliminated in consolidation.

Financial data for business segments and products and services are as follows (in millions):

	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, 2008:						
Natural Gas Distribution	$ 4,217	$ 9	$ 157	$ 215	$ 4,961	$ 214
Competitive Natural Gas Sales and Services	4,488	40	3	62	1,315	8
Interstate Pipelines (1)	477	173	46	293	3,578	189
Field Services (2)	213	39	12	147	826	122
Other	—	—	—	—	724	—
Reconciling Eliminations	—	(261)	—	—	(1,193)	—
Consolidated	$ 9,395	$ —	$ 218	$ 717	$ 10,211	$ 533
As of and for the year ended December 31, 2009:						
Natural Gas Distribution	$ 3,374	$ 10	$ 161	$ 204	$ 4,535	$ 165
Competitive Natural Gas Sales and Services	2,215	15	4	21	1,176	2
Interstate Pipelines (1)	456	142	48	256	3,484	176
Field Services (2)	212	29	15	94	1,045	348
Other	—	—	1	(6)	800	—
Reconciling Eliminations	—	(196)	—	—	(1,256)	—
Consolidated	$ 6,257	$ —	$ 229	$ 569	$ 9,784	$ 691
As of and for the year ended December 31, 2010:						
Natural Gas Distribution	$ 3,199	$ 14	$ 166	$ 231	$ 4,575	$ 202
Competitive Natural Gas Sales and Services	2,617	34	4	16	1,190	2
Interstate Pipelines (1)	464	137	52	270	3,672	102
Field Services (2)	289	49	25	151	1,803	668
Other	—	—	1	(1)	659	—
Reconciling Eliminations	—	(234)	—	—	(1,361)	—
Consolidated	$ 6,569	$ —	$ 248	$ 667	$ 10,538	$ 974

(1) Interstate Pipelines recorded equity income of $36 million, $7 million, and $19 million (including $33 million related to pre-operating allowance for funds used during construction during 2008) in the years ended December 31, 2008, 2009 and 2010, respectively, from its 50% interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Interstate Pipelines' investment in SESH was $307 million, $422 million and $413 million as of December 31, 2008, 2009 and 2010 and is included in Investment in unconsolidated affiliates.

(2) Field Services recorded equity income of $15 million, $8 million and $10 million for the years ended December 31, 2008, 2009 and 2010, respectively, from its 50% interest in a jointly-owned gas processing plant. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Field Services' investment in the jointly-owned gas processing plant was $38 million, $40 million and $55 million as of December 31, 2008, 2009 and 2010, respectively, and is included in Investment in unconsolidated affiliates.

<u>**Revenues by Products and Services:**</u>	Year Ended December 31, 2008	2009	2010
		(in millions)	
Retail gas sales	$ 6,216	$ 4,540	$ 4,412
Wholesale gas sales	2,295	902	1,250
Gas transport	756	691	785
Energy products and services	128	124	122
Total	$ 9,395	$ 6,257	$ 6,569

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

None.

Item 9A. ***Controls and Procedures.***

Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2010 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, 2010 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

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

The ratio of earnings to fixed charges as calculated pursuant to Securities and Exchange Commission rules was 2.64, 3.04, 3.30, 2.63 and 3.05 for the years ended December 31, 2006, 2007, 2008, 2009 and 2010, respectively.

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 CERC during the fiscal years ending December 31, 2009 and 2010 by its principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31, 2009	Year Ended December 31, 2010
Audit fees (1)	$ 1,105,310	$ 1,739,584
Audit-related fees (2)	118,900	78,959
Total audit and audit-related fees	1,224,210	1,818,543
Tax fees	—	—
All other fees	—	—
Total fees	$ 1,224,210	$ 1,818,543

(1) For 2010 and 2009, amounts include fees for services provided by the principal accounting firm relating to the integrated audit of financial statements and internal control over financial reporting, statutory audits, attest services, and regulatory filings.

(2) For 2010 and 2009, includes fees for consultations concerning financial accounting and reporting standards and various agreed-upon or expanded procedures related to accounting records to comply with financial accounting or regulatory reporting matters.

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

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements.

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2010.

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 78.

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, 2010 and 2009, and for each of the three years in the period ended December 31, 2010, and have issued our report thereon dated March 11, 2011; 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.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 2011

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

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

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
For the Three Years Ended December 31, 2010

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (1)	Deductions From Reserves(2)	Balance at End of Period
			(in millions)		
Year Ended December 31, 2010:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 23	$ 30	$ —	$ 28	$ 25
Deferred tax asset valuation allowance	5	(2)	—	—	3
Year Ended December 31, 2009:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 33	$ 35	$ —	$ 45	$ 23
Deferred tax asset valuation allowance	5	—	—	—	5
Year Ended December 31, 2008:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 37	$ 53	$ 3	$ 60	$ 33
Deferred tax asset valuation allowance	18	(1)	(12)	—	5

(1) The 2008 change to the deferred tax asset valuation allowance charged to other accounts represents a reduction equal to the related deferred tax asset reduction in 2008 for remeasurement of state tax attributes, net of federal tax benefit. A full valuation allowance for this deferred tax asset was established in prior periods.

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 11th day of March, 2011.

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 11, 2011.

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, 2010

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 CERC, Houston Lighting and Power Company ("HL&P"), HI Merger, Inc. and NorAm Energy Corp. ("NorAm") dated August 11, 1996	Houston Industries' ("HI's") Form 8-K dated August 11, 1996	1-7629	2
2(a)(2)	Amendment to Agreement and Plan of Merger among CERC, 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 Reliant Energy Resources Corp. ("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 February 1, 1998, between RERC Corp. and Chase Bank of Texas, National Association, as Trustee	Form 8-K dated February 5, 1998	1-13265	4.1
4(a)(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

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(a)(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(a)(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(a)(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(a)(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(a)(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(a)(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(a)(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	CenterPoint Energy, Inc.'s ("CNP's") Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(a)(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(a)(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(a)(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(a)(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(a)(14)	Supplemental Indenture No. 13 dated as of May 15, 2008, providing for the issuance of CERC Corp.'s 6.00% Senior Notes due 2018	CNP's Form 10-Q for quarter ended June 30, 2008	1-31447	4.9

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(a)(15)	Supplemental Indenture No. 14 to Exhibit 4(a)(1) dated as of January 11, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021 and 5.85% Senior Notes due 2041	CNP's Form 10-K for the year ended December 31, 2010	1-31447	4(a)(15)
4(a)(16)	Supplemental Indenture No. 15 to Exhibit 4(a)(1) dated as of January 20, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021	CNP's Form 10-K for the year ended December 31, 2010	1-31447	4(a)(16)
4(b)	$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,				
	2006	2007 (1)	2008 (1)	2009 (1)	2010 (1)
Net Income	$ 207	$ 287	$ 343	$ 230	$ 300
Equity in earnings of unconsolidated affiliates, net of distributions	(5)	(13)	(51)	(3)	13
Income taxes	116	173	228	146	187
Capitalized interest	(6)	(12)	(5)	(2)	(7)
	312	435	515	371	493
Fixed charges, as defined:					
Interest	167	187	206	213	208
Capitalized interest	6	12	5	2	7
Interest component of rentals charged to operating expense	17	14	13	12	25
Total fixed charges	190	213	224	227	240
Earnings, as defined	$ 502	$ 648	$ 739	$ 598	$ 733
Ratio of earnings to fixed charges	2.64	3.04	3.30	2.63	3.05

(1) Excluded from the computation of fixed charges for the years ended December 31, 2007, 2008, 2009 and 2010 is interest income of $2 million, $1 million, $-0- and $1 million, respectively, 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. 333-169666-01 on Form S-3 of our reports dated March 11, 2011, relating to the consolidated financial statements and consolidated financial statement schedule of CenterPoint Energy Resources Corp. and subsidiaries appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2010.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 11, 2011

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 11, 2011

/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 11, 2011

/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, 2010 (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 11, 2011

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, 2010 (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 11, 2011