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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to______

Commission File Number 1-31447

CenterPoint Energy, Inc.
(Exact name of registrant as specified in its charter)

Texas	**74-0694415**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1111 Louisiana **Houston, Texas 77002**	**(713) 207-1111**
(Address and zip code of principal executive offices)	*(Registrant's telephone number, including area code)*

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value and associated rights to purchase preferred stock	New York Stock Exchange Chicago Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No o

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

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

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

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

Large accelerated filer ☑	Accelerated filer o	Non-accelerated filer o (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 in Rule 12b-2 of the Exchange Act). Yes o No ☑

The aggregate market value of the voting stock held by non-affiliates of CenterPoint Energy, Inc. (Company) was $5,552,435,108 as of June 30, 2007, using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of February 15, 2008, the Company had 327,346,112 shares of Common Stock outstanding. Excluded from the number of shares of Common Stock outstanding are 166 shares held by the Company as treasury stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2008 Annual Meeting of Shareholders of the Company, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2007, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement.

PART I

Item 1. *Business*

OUR BUSINESS

Overview

We are a public utility holding company whose indirect wholly owned subsidiaries include:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in a 5,000-square mile area of the Texas Gulf Coast that includes Houston; and
- CenterPoint Energy Resources Corp. (CERC Corp., and, together with its subsidiaries, CERC), which 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 Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

Our reportable business segments are Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. The operations of Texas Genco Holdings, Inc. (Texas Genco), formerly our majority owned electric generating subsidiary, the sale of which was completed in April 2005, are presented as discontinued 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 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). Additionally, we make available free of charge on our Internet website:

- our Code of Ethics for our Chief Executive Officer and Senior Financial Officers;
- our Ethics and Compliance Code;
- our Corporate Governance Guidelines; and
- the charters of our audit, compensation, finance and governance committees.

Any shareholder who so requests may obtain a printed copy of any of these documents from us. Changes in or waivers of our Code of Ethics for our Chief Executive Officer and Senior Financial Officers and waivers of our Ethics and Compliance Code for directors or executive officers will be posted on our Internet website within five business days of such change or waiver and maintained for at least 12 months or reported on Item 5.05 of Form 8-K. Our website address is *www.centerpointenergy.com.* Except to the extent explicitly stated herein, documents and information on our website are not incorporated by reference herein.

Electric Transmission & Distribution

In 1999, the Texas legislature adopted the Texas Electric Choice Plan (Texas electric restructuring law) that led to the restructuring of integrated electric utilities operating within Texas. Pursuant to that legislation, integrated electric utilities operating within the Electric Reliability Council of Texas, Inc. (ERCOT) were required to separate their integrated operations into separate retail sales, power generation and transmission and distribution companies. The legislation also required that the prices for wholesale generation and retail electric sales be unregulated, but services by companies providing transmission and distribution service, such as CenterPoint Houston, would continue to be regulated by the Public Utility Commission of Texas (Texas Utility Commission). The legislation provided for a transition period to move to the new market structure and provided a true-up mechanism for the formerly integrated electric utilities to recover stranded and certain other costs resulting from the transition to competition. Those costs are recoverable after approval by the Texas Utility Commission either through the issuance of securitization bonds or through the implementation of a competition transition charge (CTC) as a rider to the utility's tariff.

CenterPoint Houston is the only business of CenterPoint Energy that continues to engage in electric utility operations. It is a transmission and distribution electric utility that operates wholly within the state of Texas. Neither CenterPoint Houston nor any other subsidiary of CenterPoint Energy makes sales of electric energy at retail or wholesale, or owns or operates any electric generating facilities.

Electric Transmission

On behalf of retail electric providers (REPs), CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers taking power at or above 69 kilovolts (kV) in locations throughout the control area managed by ERCOT. CenterPoint Houston provides transmission services under tariffs approved by the Texas Utility Commission.

Electric Distribution

In ERCOT, end users purchase their electricity directly from certificated REPs. CenterPoint Houston delivers electricity for REPs in its certificated service area by carrying lower-voltage power from the substation to the retail electric customer. CenterPoint Houston's distribution network receives electricity from the transmission grid through power distribution substations and delivers electricity to end users through distribution feeders. CenterPoint Houston's operations include construction and maintenance of electric transmission and distribution facilities, metering services, outage response services and call center operations. CenterPoint Houston provides distribution services under tariffs approved by the Texas Utility Commission. Texas Utility Commission rules and market protocols govern the commercial operations of distribution companies and other market participants. Rates for these existing services may be reviewed only through rate cases conducted before the Texas Utility Commission.

ERCOT Market Framework

CenterPoint Houston is a member of ERCOT. ERCOT serves as the regional reliability coordinating council for member electric power systems in Texas. ERCOT membership is open to consumer groups, investor and municipally owned electric utilities, rural electric cooperatives, independent generators, power marketers and REPs. The ERCOT market includes most of the State of Texas, other than a portion of the panhandle, a portion of the eastern part of the state bordering Louisiana and the area in and around El Paso. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation's largest power markets. The ERCOT market includes an aggregate net generating capacity of approximately 72,000 megawatts (MW). There are only limited direct current interconnections between the ERCOT market and other power markets in the United States and Mexico.

The ERCOT market operates under the reliability standards set by the North American Electric Reliability Council (NERC) and approved by the Federal Energy Regulatory Commission (FERC). These reliability standards are administered by the Texas Regional Entity, a Division of ERCOT (TRE). The Texas Utility Commission has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity supply across the state's main interconnected power transmission grid. The ERCOT independent system operator (ERCOT ISO) is responsible for operating the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers. Unlike certain other regional power markets, the ERCOT market is not a centrally dispatched power pool, and the ERCOT ISO does not procure energy on behalf of its members other than to maintain the reliable operations of the transmission system. Members who sell and purchase power are responsible for contracting sales and purchases of power bilaterally. The ERCOT ISO also serves as agent for procuring ancillary services for those members who elect not to provide their own ancillary services.

CenterPoint Houston's electric transmission business, along with those of other owners of transmission facilities in Texas, supports the operation of the ERCOT ISO. The transmission business has planning, design, construction, operation and maintenance responsibility for the portion of the transmission grid and for the load-serving substations it owns, primarily within its certificated area. We participate with the ERCOT ISO and other ERCOT utilities to plan, design, obtain regulatory approval for and construct new transmission lines necessary to increase bulk power transfer capability and to remove existing constraints on the ERCOT transmission grid.

Recovery of True-Up Balance

The Texas electric restructuring law substantially amended the regulatory structure governing electric utilities in order to allow retail competition for electric customers beginning in January 2002. The Texas electric restructuring law required the Texas Utility Commission to conduct a “true-up” proceeding to determine CenterPoint Houston’s stranded costs and certain other costs resulting from the transition to a competitive retail electric market and to provide for its recovery of those costs.

In March 2004, CenterPoint Houston filed its true-up application with the Public Utility Commission of Texas (Texas Utility Commission), requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas Electric Choice Plan (Texas electric restructuring law). In December 2004, the Texas Utility Commission issued its final order (True-Up Order) allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and provided for adjustment of the amount to be recovered to include interest on the balance until recovery, along with the principal portion of additional excess mitigation credits (EMCs) returned to customers after August 31, 2004 and in certain other respects.

CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, that court issued its judgment on the various appeals. In its judgment, the district court:

- reversed the Texas Utility Commission’s ruling that had denied recovery of a portion of the capacity auction true-up amounts;
- reversed the Texas Utility Commission’s ruling that precluded CenterPoint Houston from recovering the interest component of the EMCs paid to REPs; and
- affirmed the True-Up Order in all other respects.

The district court’s decision would have had the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston’s initial request.

CenterPoint Houston and other parties appealed the district court’s judgment to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court’s judgment to the extent it restored the capacity auction true-up amounts;
- reversed the district court’s judgment to the extent it upheld the Texas Utility Commission’s decision to allow CenterPoint Houston to recover EMCs paid to Reliant Energy, Inc. (RRI);
- ordered that the tax normalization issue described below be remanded to the Texas Utility Commission; and
- affirmed the district court’s judgment in all other respects.

CenterPoint Houston and two other parties filed motions for rehearing with the court of appeals. In the event that the motions for rehearing are not resolved in a manner favorable to it, CenterPoint Houston intends to seek further review by the Texas Supreme Court. Although we and CenterPoint Houston believe that CenterPoint Houston’s true-up request is consistent with applicable statutes and regulations and accordingly that it is reasonably possible that it will be successful in its further appeals, we can provide no assurance as to the ultimate rulings by the courts on the issues to be considered in the various appeals or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue described below.

To reflect the impact of the True-Up Order, in 2004 and 2005 we recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court’s judgment or the decision of the court of appeals have been recorded in our consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of the pending motions for rehearing or on further review by the Texas Supreme Court, we anticipate that we would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue described below and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $130 million to $350 million, plus interest subsequent to December 31, 2007.

In the True-Up Order the Texas Utility Commission reduced CenterPoint Houston's stranded cost recovery by approximately $146 million, which was included in the extraordinary loss discussed above, for the present value of certain deferred tax benefits associated with its former electric generation assets. We believe that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 which would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, in December 2005, the IRS withdrew those proposed normalization regulations and issued new proposed regulations that do not include the provision allowing a retroactive election to pass the tax benefits back to customers. We subsequently requested a Private Letter Ruling (PLR) asking the IRS whether the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations. In that ruling, which was received in August 2007, the IRS concluded that such reductions would cause normalization violations with respect to the ADITC and EDFIT. As in a similar PLR issued in May 2006 to another Texas utility, the IRS did not reference its proposed regulations.

The district court affirmed the Texas Utility Commission's ruling on the tax normalization issue, but in response to a request from the Texas Utility Commission, the court of appeals ordered that the tax normalization issue be remanded for further consideration. If the Texas Utility Commission's order relating to the ADITC reduction is not reversed or otherwise modified on remand so as to eliminate the normalization violation, the IRS could require us to pay an amount equal to CenterPoint Houston's unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. Such treatment if required by the IRS, could have a material adverse impact on our results of operations, financial condition and cash flows in addition to any potential loss resulting from final resolution of the True-Up Order. However, we and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate or administrative process. Although the Texas Utility Commission has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation, no prediction can be made as to the ultimate action the Texas Utility Commission may take on this issue on remand.

The Texas electric restructuring law allowed the amounts awarded to CenterPoint Houston in the Texas Utility Commission's True-Up Order to be recovered either through the issuance of transition bonds or through implementation of a competition transition charge (CTC) or both. Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed by a Travis County district court, in December 2005 a subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84% to 5.30% and final maturity dates ranging from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

In July 2005, CenterPoint Houston received an order from the Texas Utility Commission allowing it to implement a CTC designed to collect the remaining $596 million from the True-Up Order over 14 years plus interest at an annual rate of 11.075% (CTC Order). The CTC Order authorized CenterPoint Houston to impose a charge on REPs to recover the portion of the true-up balance not recovered through a financing order. The CTC Order also allowed CenterPoint Houston to collect approximately $24 million of rate case expenses over three years without a return through a separate tariff rider (Rider RCE). CenterPoint Houston implemented the CTC and Rider RCE effective September 13, 2005 and began recovering approximately $620 million. Effective September 13, 2005, the return on the CTC portion of the true-up balance is included in CenterPoint Houston's tariff-based revenues.

Certain parties appealed the CTC Order to a district court in Travis County. In May 2006, the district court issued a judgment reversing the CTC Order in three respects. First, the court ruled that the Texas Utility

Commission had improperly relied on provisions of its rule dealing with the interest rate applicable to CTC amounts. The district court reached that conclusion based on its belief that the Texas Supreme Court had previously invalidated that entire section of the rule. The 11.075% interest rate in question was applicable from the implementation of the CTC Order on September 13, 2005 until August 1, 2006, the effective date of the implementation of a new CTC in compliance with the new rule discussed below. Second, the district court reversed the Texas Utility Commission's ruling that allows CenterPoint Houston to recover through the Rider RCE the costs (approximately $5 million) for a panel appointed by the Texas Utility Commission in connection with the valuation of electric generation assets. Finally, the district court accepted the contention of one party that the CTC should not be allocated to retail customers that have switched to new on-site generation. The Texas Utility Commission and CenterPoint Houston disagree with the district court's conclusions and, in May 2006, appealed the judgment to the Texas Third Court of Appeals, and if required, CenterPoint Houston plans to seek further review from the Texas Supreme Court. All briefs in the appeal have been filed, and oral arguments were held in December 2006. The ultimate outcome of this matter cannot be predicted at this time. However, we do not expect the disposition of this matter to have a material adverse effect on our or CenterPoint Houston's financial condition, results of operations or cash flows.

In June 2006, the Texas Utility Commission adopted the revised rule governing the carrying charges on unrecovered CTC balances as recommended by its staff (Staff). The rule, which applies to CenterPoint Houston, reduced the allowed interest rate on the unrecovered CTC balance prospectively from 11.075% to a weighted average cost of capital of 8.06%. The annualized impact on operating income is a reduction of approximately $18 million per year for the first year with lesser impacts in subsequent years. In July 2006, CenterPoint Houston made a compliance filing necessary to implement the rule changes effective August 1, 2006.

During the years ended December 31, 2005, 2006 and 2007, CenterPoint Houston recognized approximately $19 million, $55 million and $42 million, respectively, in operating income from the CTC. Additionally, during the years ended December 31, 2005, 2006 and 2007, CenterPoint Houston recognized approximately $1 million, $13 million and $14 million, respectively, of the allowed equity return not previously recorded. As of December 31, 2007, we have not recorded an allowed equity return of $220 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates.

During the 2007 legislative session, the Texas legislature amended statutes prescribing the types of true-up balances that can be securitized by utilities and authorized the issuance of transition bonds to recover the balance of the CTC. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of the remaining balance of the CTC, after taking into account the environmental refund and the fuel reconciliation settlement amounts discussed below. CenterPoint Houston reached substantial agreement with other parties to this proceeding, and a financing order was approved by the Texas Utility Commission in September 2007. In February 2008, a new special purpose subsidiary of CenterPoint Houston issued approximately $488 million of transition bonds pursuant to the financing order in two tranches with interest rates of 4.192% and 5.234% and final maturity dates of February 2020 and February 2023, respectively. Contemporaneously with the issuance of those bonds, the CTC was terminated and a transition charge was implemented.

Refund of Environmental Retrofit Costs

The True-Up Order allowed recovery of approximately $699 million of environmental retrofit costs related to CenterPoint Houston's generation assets. The True-Up Order required CenterPoint Houston to provide evidence by January 31, 2007 that the entire $699 million was actually spent by December 31, 2006 on environmental programs and provided for the Texas Utility Commission to determine the appropriate manner to return to customers any unused portion of these funds, including interest on the funds and on stranded costs attributable to the environmental costs portion of the stranded costs recovery. In January 2007, the successor in interest to CenterPoint Houston's generation assets advised that, as of December 31, 2006, it had spent only approximately $664 million. On January 31, 2007, CenterPoint Houston made the required filing with the Texas Utility Commission, identifying approximately $35 million in unspent funds to be refunded to customers along with approximately $7 million of interest and requesting permission to refund these amounts through a reduction of the CTC. Such amounts were recorded as regulatory liabilities as of December 31, 2006. In July 2007, CenterPoint Houston, the Staff and the other parties filed a settlement agreement in which it was agreed that the total amount of the refund, including all principal and interest, was $45 million as of May 31, 2007, that interest would continue to accrue after May 31, 2007 on any unrefunded balance at a rate of 5.4519% per year and that the refund should be used to offset the principal amount proposed in CenterPoint Houston's application to securitize the CTC and other amounts. The offset occurred in connection with the approximately $488 million of transition bonds issued in February 2008. In August 2007, the Texas Utility Commission issued a final order consistent with the terms of that settlement agreement. As of December 31, 2007, CenterPoint Houston had recorded a regulatory liability of $46 million related to this matter.

Final Fuel Reconciliation

The results of the Texas Utility Commission's final decision related to CenterPoint Houston's final fuel reconciliation were a component of the True-Up Order. CenterPoint Houston appealed certain portions of the True-Up Order involving a disallowance of approximately $67 million relating to the final fuel reconciliation in 2003 plus interest of $10 million. That decision was upheld by a Travis County district court and affirmed by the Texas Third Court of Appeals. Although it filed an appeal with the Texas Supreme Court, in February 2007 CenterPoint Houston asked the Texas Supreme Court to hold that appeal in abeyance pending consideration by the Texas Utility Commission of a tentative settlement reached by the parties. In October 2007, the Texas Utility Commission issued a final order consistent with the settlement, and the Texas Supreme Court ultimately vacated the lower court decisions. The settlement allows CenterPoint Houston recovery of $12.5 million plus interest from January 2002. As a result of the settlement, CenterPoint Houston recorded a regulatory asset of $17 million in 2007.

Customers

CenterPoint Houston serves nearly all of the Houston/Galveston metropolitan area. CenterPoint Houston's customers consist of 74 REPs, which sell electricity to approximately 2 million metered customers in CenterPoint Houston's certificated service area, and municipalities, electric cooperatives and other distribution companies located outside CenterPoint Houston's certificated service area. Each REP is licensed by, and must meet minimal creditworthiness criteria established by the Texas Utility Commission. Two of the REPs in CenterPoint Houston's service area are subsidiaries of RRI. Sales to subsidiaries of RRI represented approximately 62%, 56% and 51% of CenterPoint Houston's transmission and distribution revenues in 2005, 2006 and 2007, respectively. CenterPoint Houston's billed receivables balance from REPs as of December 31, 2007 was $141 million. Approximately 48% of this amount was owed by subsidiaries of RRI. CenterPoint Houston does not have long-term contracts with any of its customers. It operates on a continuous billing cycle, with meter readings being conducted and invoices being distributed to REPs each business day.

Advanced Metering System and Distribution Automation (Intelligent Grid)

CenterPoint Houston is pursuing development and possible deployment of an advanced metering system (AMS) and electric distribution grid automation strategy that involves the implementation of an "Intelligent Grid" which would make use of CenterPoint Houston's lines and other facilities to provide on-demand data and information about electricity usage and the status of facilities on our system. Although this technology is still in the developmental stage, CenterPoint Houston believes it has the potential to enable customers of the REPs to better monitor and control their usage of electricity as well as offer a significant improvement in metering, grid planning, operations and maintenance of the CenterPoint Houston distribution system. These improvements would be expected to contribute to fewer and shorter outages, better customer service, improved operations costs, improved security and more effective use of our workforce. In May 2007, the Texas Utility Commission issued rules establishing minimum functionality requirements for an AMS and a surcharge mechanism to enable timely recovery of the costs of implementation. To date, CenterPoint Houston has deployed approximately 10,000 advanced meters and utilized broadband over power line technology as part of a limited deployment to help in proving the technology and in validating its potential benefits prior to a full-scale implementation. CenterPoint Houston would be required to file its deployment plan for approval by the Texas Utility Commission prior to full scale implementation of this technology.

Competition

There are no other electric transmission and distribution utilities in CenterPoint Houston's service area. In order for another provider of transmission and distribution services to provide such services in CenterPoint Houston's territory, it would be required to obtain a certificate of convenience and necessity from the Texas Utility Commission and, depending on the location of the facilities, may also be required to obtain franchises from one or more municipalities. We know of no other party intending to enter this business in CenterPoint Houston's service area at this time.

Seasonality

A significant portion of CenterPoint Houston's revenues is derived from rates that it collects from each REP based on the amount of electricity it distributes on behalf of such REP. Thus, CenterPoint Houston's revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues being higher during the warmer months.

Properties

All of CenterPoint Houston's properties are located in Texas. Its properties consist primarily of high voltage electric transmission lines and poles, distribution lines, substations, service wires and meters. Most of CenterPoint Houston's transmission and distribution lines have been constructed over lands of others pursuant to easements or along public highways and streets as permitted by law.

All real and tangible properties of CenterPoint Houston, subject to certain exclusions, are currently subject to:

- the lien of a Mortgage and Deed of Trust (the Mortgage) dated November 1, 1944, as supplemented; and
- the lien of a General Mortgage (the General Mortgage) dated October 10, 2002, as supplemented, which is junior to the lien of the Mortgage.

As of December 31, 2007, CenterPoint Houston had outstanding $2.0 billion aggregate principal amount of general mortgage bonds under the General Mortgage, including approximately $527 million held in trust to secure pollution control bonds for which CenterPoint Energy is obligated and approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had outstanding approximately $253 million aggregate principal amount of first mortgage bonds under the Mortgage, including approximately $151 million held in trust to secure certain pollution control bonds for which CenterPoint Energy is obligated. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $2.3 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2007. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

Electric Lines — Overhead. As of December 31, 2007, CenterPoint Houston owned 27,421 pole miles of overhead distribution lines and 3,738 circuit miles of overhead transmission lines, including 424 circuit miles operated at 69,000 volts, 2,098 circuit miles operated at 138,000 volts and 1,216 circuit miles operated at 345,000 volts.

Electric Lines — Underground. As of December 31, 2007, CenterPoint Houston owned 18,955 circuit miles of underground distribution lines and 28.4 circuit miles of underground transmission lines, including 4.5 circuit miles operated at 69,000 volts and 23.9 circuit miles operated at 138,000 volts.

Substations. As of December 31, 2007, CenterPoint Houston owned 229 major substation sites having total installed rated transformer capacity of 50,586 megavolt amperes.

Service Centers. CenterPoint Houston operates 14 regional service centers located on a total of 291 acres of land. These service centers consist of office buildings, warehouses and repair facilities that are used in the business of transmitting and distributing electricity.

Franchises

CenterPoint Houston holds non-exclusive franchises from the incorporated municipalities in its service territory. In exchange for the payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 50 years.

Natural Gas Distribution

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

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

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

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

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

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

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

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

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

Assets

As of December 31, 2007, Gas Operations owned approximately 69,000 linear miles of natural gas distribution mains, varying in size from one-half inch to 24 inches in diameter. Generally, in each of the cities, towns and rural areas served by Gas Operations, it owns the underground gas mains and service lines, metering and regulating equipment located on customers' premises and the district regulating equipment necessary for pressure maintenance. With a few exceptions, the measuring stations at which Gas Operations receives gas are owned, operated and maintained by others, and its distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on the land owned by suppliers.

Competition

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

Competitive Natural Gas Sales and Services

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

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

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

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

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

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

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

The CenterPoint Energy risk control policy, governed by 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 are consistent with its operational objective of matching its aggregate sales obligations (including the swing associated with load following services) with its supply portfolio in a manner that minimizes its total cost of supply.

Assets

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

Competition

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

Interstate Pipelines

CERC's pipelines business operates interstate natural gas pipelines with gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. CERC's interstate pipeline operations are primarily conducted by two wholly owned subsidiaries that provide gas transportation and storage services primarily to industrial customers and local distribution companies:

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

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

In 2007, approximately 20% of CEGT and MRT's total operating revenue was attributable to services provided to Gas Operations and approximately 10% was attributable to services provided to Laclede Gas Company (Laclede), an unaffiliated distribution company that provides natural gas utility service to the greater St. Louis metropolitan area in Illinois and Missouri. Services to Gas Operations and Laclede are provided under several long-term firm storage and transportation agreements. Since October 31, 2006, MRT's contract with Laclede has been terminable upon one year's prior notice. MRT has not received a termination notice and is currently negotiating a long-term contract with Laclede. Agreements for firm transportation, "no notice" transportation service and storage service in certain of Gas Operations' service areas (Arkansas, Louisiana and Oklahoma) expire in 2012.

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

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

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

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

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

Assets

Our interstate pipelines business currently owns and operates approximately 8,100 miles of natural gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. It also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.2 Bcf per day and a combined working gas capacity of approximately 59.0 Bcf. It also owns a 10% interest in the Bistineau storage facility located in Bienville Parish, Louisiana, with the remaining interest owned and operated by Gulf South Pipeline Company, LP. This facility has a total working gas capacity of 85.7 Bcf and approximately 1.1 Bcf per day of deliverability. Storage capacity in the Bistineau facility is 8 Bcf of working gas with 100 MMcf per day of deliverability. Most storage operations are in north Louisiana and Oklahoma.

Competition

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

Field Services

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

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

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

Assets

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

Competition

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

Other Operations

Our Other Operations business segment includes office buildings and other real estate used in our business operations and other corporate operations that support all of our business operations.

Discontinued Operations

In July 2004, we announced our agreement to sell our majority owned subsidiary, Texas Genco, to Texas Genco LLC. In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco, whose principal remaining asset was its ownership interest in a nuclear generating facility, distributed $2.231 billion in cash to us. The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to us of $700 million, was completed in April 2005.

We recorded an after-tax loss of $3 million for the year ended December 31, 2005, related to the operations of Texas Genco. The consolidated financial statements report these operations for all periods presented as discontinued operations in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

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

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

CenterPoint Houston is not a "public utility" under the Federal Power Act and therefore is not generally regulated by the FERC, although certain of its transactions are subject to limited FERC jurisdiction. The Energy Act conferred new jurisdiction and responsibilities on the FERC with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by CenterPoint Houston and other utilities within ERCOT. Under this authority, the FERC has designated the NERC as the Electric Reliability Organization (ERO) to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system (Electric Entities). The ERO and the FERC have authority to impose fines and other sanctions on Electric Entities that fail to comply with the standards. The FERC has approved the delegation by the NERC of authority for reliability in ERCOT to the Texas Regional Entity, a division of ERCOT. CenterPoint Houston does not anticipate that the reliability standards proposed by the NERC and approved by the FERC will have a material adverse impact on its operations. To the extent that CenterPoint Houston is required to make additional expenditures to comply with these standards, it is anticipated that CenterPoint Houston will seek to recover those costs through the transmission charges that are imposed on all distribution service providers within ERCOT for electric transmission provided.

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

State and Local Regulation

Electric Transmission & Distribution

CenterPoint Houston conducts its operations pursuant to a certificate of convenience and necessity issued by the Texas Utility Commission that covers its present service area and facilities. The Texas Utility Commission and those municipalities that have retained original jurisdiction have the authority to set the rates and terms of service provided by CenterPoint Houston under cost of service rate regulation. CenterPoint Houston holds non-exclusive franchises from the incorporated municipalities in its service territory. In exchange for payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 50 years.

CenterPoint Houston's distribution rates charged to REPs for residential customers are based on amounts of energy delivered, whereas distribution rates for a majority of commercial and industrial customers are based on peak demand. All REPs in CenterPoint Houston's service area pay the same rates and other charges for the same transmission and distribution services. Transmission rates charged to other distribution companies are based on amounts of energy transmitted under "postage stamp" rates that do not vary with the distance the energy is being transmitted. All distribution companies in ERCOT pay CenterPoint Houston the same rates and other charges for transmission services. This regulated delivery charge includes the transmission and distribution rate (which includes municipal franchise fees), a system benefit fund fee imposed by the Texas electric restructuring law, a nuclear decommissioning charge associated with decommissioning the South Texas nuclear generating facility, transition charges associated with securitization of regulatory assets and securitization of stranded costs, a competition transition charge for collection of the true-up balance not securitized and a rate case expense charge.

Recovery of True-Up Balance. For a discussion of CenterPoint Houston's true-up proceedings, see "— Our Business — Electric Transmission & Distribution — Recovery of True-Up Balance" above.

CenterPoint Houston Rate Agreement. CenterPoint Houston's transmission and distribution rates are subject to the terms of a Settlement Agreement effective in October 2006. The Settlement Agreement provides that until June 30, 2010 CenterPoint Houston will not seek to increase its base rates and the other parties will not petition to decrease those rates. The rate freeze is subject to adjustment for certain limited matters, including the results of the appeals of the True-Up Order and the implementation of charges associated with securitizations. CenterPoint Houston must make a new base rate filing not later than June 30, 2010, based on a test year ended December 31, 2009, unless the staff of the Texas Utility Commission and certain cities notify it that such a filing is unnecessary.

Natural Gas Distribution

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

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

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

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

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

In response to an explosion resulting from the failure of a certain type of compression coupling on another company's natural gas distribution system in Texas, the Railroad Commission has begun a rulemaking focusing on leak surveys, leak grading and the replacement of specific types of compression couplings. In addition, the Railroad Commission issued a directive in November 2007 requiring the removal of service risers known to have compression fittings that do not meet certain performance specifications. After reviewing our records as required by the directive, Gas Operations has no indication that we have the type of coupling described in that directive.

However, at this time we do not know what additional requirements may result from the pending Railroad Commission rulemaking or what impacts on our gas operations may result from any future regulatory initiatives adopted with respect to this issue.

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

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

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

Department of Transportation

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

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

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

ENVIRONMENTAL MATTERS

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

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

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

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

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

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

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

Global Climate Change

In recent years, there has been increasing public debate regarding the potential impact on global climate change by various “greenhouse gases” such as carbon dioxide, a byproduct of burning fossil fuels, and methane, a component of the natural gas which we transport and deliver to customers. Legislation to regulate emissions of greenhouse gases has been introduced in Congress, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industries such as the utility industry to meet stringent new standards requiring substantial reductions in carbon emissions. Those reductions could be costly and difficult to implement. Some proposals would provide for credits to those who reduce emissions below certain levels and would allow those credits to be traded and/or sold to others. It is too early to determine whether, and in what form, a regulatory scheme regarding greenhouse gas emissions will be adopted or what specific impacts a new regulatory scheme might have on us and our subsidiaries. However, as a distributor and transporter of natural gas and consumer of natural gas in its pipeline and gathering businesses, CERC's revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory scheme which would reduce consumption of natural gas if ultimately adopted. Our electric transmission and distribution business, unlike most electric utilities, does not generate electricity and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that are in the business of generating electricity. Nevertheless, CenterPoint Houston's revenues could be adversely affected to the extent any resulting regulatory scheme has the effect of reducing consumption of electricity by ultimate consumers within its service territory.

Air Emissions

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

Water Discharges

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

Hazardous Waste

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

Liability for Remediation

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

Liability for Preexisting Conditions

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

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

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

In addition to the Minnesota sites, the EPA and other regulators have investigated MGP sites that were owned or operated by 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 the subject of the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. We are investigating details regarding this site and the range of environmental expenditures for potential remediation. However, CERC believes it is not liable as a former owner or operator of the site under CERCLA and applicable state statutes, and is vigorously contesting the suit and its designation as a PRP.

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

Asbestos. Some of our facilities contain or have contained asbestos insulation and other asbestos-containing materials. We or our subsidiaries have been named, along with numerous others, as a defendant in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos. Some of the claimants have worked at locations owned by us, but most existing claims relate to facilities previously owned by our subsidiaries. We anticipate that additional claims like those received may be asserted in the future. In 2004, we sold our generating business, to which most of these claims relate, to Texas Genco LLC, which is now known as NRG Texas LP (NRG). Under the terms of the arrangements regarding separation of the generating business from us and our sale of this business to Texas Genco LLC, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by Texas Genco LLC and its successor, but we have agreed to continue to defend such claims to the extent they are covered by insurance we maintain, subject to reimbursement of the costs of such defense from the purchaser. Although their ultimate outcome cannot be predicted at this time, we intend to continue vigorously contesting claims that we do not consider to have merit and do not expect, based on our experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on our financial condition, results of operations or cash flows.

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

EMPLOYEES

As of December 31, 2007, we had 8,568 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
Electric Transmission & Distribution	2,746	1,194
Natural Gas Distribution	3,685	1,412
Competitive Natural Gas Sales and Services	117	—
Interstate Pipelines	611	—
Field Services	196	—
Other Operations	1,213	—
Total	8,568	2,606

As of December 31, 2007, approximately 30% of our employees are subject to collective bargaining agreements. We have four collective bargaining agreements, (1) United Steel Workers (USW) Local 13-227, (2) Office and Professional Employees International Union (OPEIU) Local 12 Metro, (3) OPEIU Local 12 Mankato, and (4) USW Local 13-1, that are scheduled to expire in 2008 that collectively cover approximately 8% of our employees. We have a good relationship with these bargaining units and expect to renegotiate new agreements in 2008.

EXECUTIVE OFFICERS
(as of February 28, 2008)

Name	Age	Title
David M. McClanahan	58	President and Chief Executive Officer and Director
Scott E. Rozzell	58	Executive Vice President, General Counsel and Corporate Secretary
Gary L. Whitlock	58	Executive Vice President and Chief Financial Officer
Walter L. Fitzgerald	50	Senior Vice President and Chief Accounting Officer
Byron R. Kelley	60	Senior Vice President and Group President, CenterPoint Energy Pipelines and Field Services
Thomas R. Standish	58	Senior Vice President and Group President — Regulated Operations

David M. McClanahan has been President and Chief Executive Officer and a director of CenterPoint Energy since September 2002. He served as Vice Chairman of Reliant Energy, Incorporated (Reliant Energy) from October 2000 to September 2002 and as President and Chief Operating Officer of Reliant Energy's Delivery Group from April 1999 to September 2002. He has served in various executive capacities with CenterPoint Energy since 1986. He previously served as Chairman of the Board of Directors of ERCOT and Chairman of the Board of the University of St. Thomas in Houston. He currently serves on the board of the Edison Electric Institute and as the Chairman of the Board of Directors of the American Gas Association.

Scott E. Rozzell has served as Executive Vice President, General Counsel and Corporate Secretary of CenterPoint Energy since September 2002. He served as Executive Vice President and General Counsel of the Delivery Group of Reliant Energy from March 2001 to September 2002. Before joining CenterPoint Energy in 2001, Mr. Rozzell was a senior partner in the law firm of Baker Botts L.L.P. He currently serves on the Board of Directors of the Association of Electric Companies of Texas.

Gary L. Whitlock has served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since September 2002. He served as Executive Vice President and Chief Financial Officer of the Delivery Group of Reliant Energy from July 2001 to September 2002. Mr. Whitlock served as the Vice President, Finance and Chief Financial Officer of Dow AgroSciences, a subsidiary of The Dow Chemical Company, from 1998 to 2001.

Walter L. Fitzgerald has served as Senior Vice President and Chief Accounting Officer of CenterPoint Energy since December 2007. He served as Vice President and Controller from October 2001 to December 2007. Before joining CenterPoint Energy in 2001, Mr. Fitzgerald was Controller of DuPont Dow Elastomers, from 1997 to 2001.

Byron R. Kelley has served as Senior Vice President and Group President of CenterPoint Energy Pipelines and Field Services since June 2004, having previously served as President and Chief Operating Officer of CenterPoint Energy Pipelines and Field Services from May 2003 to June 2004. Prior to joining CenterPoint Energy he served as President of El Paso International, a subsidiary of El Paso Corporation, from January 2001 to August 2002. He currently serves on the Board of Directors of the Interstate Natural Gas Association of America.

Thomas R. Standish has served as Senior Vice President and Group President-Regulated Operations of CenterPoint Energy since August 2005, having previously served as Senior Vice President and Group President and Chief Operating Officer of CenterPoint Houston from June 2004 to August 2005 and as President and Chief

Operating Officer of CenterPoint Houston from August 2002 to June 2004. He served as President and Chief Operating Officer for both electricity and natural gas for Reliant Energy's Houston area from 1999 to August 2002. Mr. Standish has served in various executive capacities with CenterPoint Energy since 1993.

Item 1A. *Risk Factors*

We are a holding company that conducts all of our business operations through subsidiaries, primarily CenterPoint Houston and CERC. 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 the businesses conducted by each of these subsidiaries:

Risk Factors Affecting Our Electric Transmission & Distribution Business

CenterPoint Houston may not be successful in ultimately recovering the full value of its true-up components, which could result in the elimination of certain tax benefits and could have an adverse impact on CenterPoint Houston's results of operations, financial condition and cash flows.

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas electric restructuring law. In December 2004, the Texas Utility Commission issued the True-Up Order allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and provided for adjustment of the amount to be recovered to include interest on the balance until recovery, along with the principal portion of additional EMCs returned to customers after August 31, 2004 and in certain other respects.

CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, that court issued its judgment on the various appeals. In its judgment, the district court:

- reversed the Texas Utility Commission's ruling that had denied recovery of a portion of the capacity auction true-up amounts;
- reversed the Texas Utility Commission's ruling that precluded CenterPoint Houston from recovering the interest component of the EMCs paid to REPs; and
- affirmed the True-Up Order in all other respects.

The district court's decision would have had the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston's initial request.

CenterPoint Houston and other parties appealed the district court's judgment to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court's judgment to the extent it restored the capacity auction true-up amounts;
- reversed the district court's judgment to the extent it upheld the Texas Utility Commission's decision to allow CenterPoint Houston to recover EMCs paid to RRI;
- ordered that the tax normalization issue described below be remanded to the Texas Utility Commission; and
- affirmed the district court's judgment in all other respects.

CenterPoint Houston and two other parties filed motions for rehearing with the court of appeals. In the event that the motions for rehearing are not resolved in a manner favorable to it, CenterPoint Houston intends to seek further review by the Texas Supreme Court. Although we and CenterPoint Houston believe that CenterPoint Houston's true-up request is consistent with applicable statutes and regulations and accordingly that it is reasonably possible that it will be successful in its further appeals, we can provide no assurance as to the ultimate rulings by the courts on the issues to be considered in the various appeals or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue described below.

To reflect the impact of the True-Up Order, in 2004 and 2005 we recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in our consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of the pending motions for rehearing or on further review by the Texas Supreme Court, we anticipate that we would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue described below and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $130 million to $350 million, plus interest subsequent to December 31, 2007.

In the True-Up Order the Texas Utility Commission reduced CenterPoint Houston's stranded cost recovery by approximately $146 million, which was included in the extraordinary loss discussed above, for the present value of certain deferred tax benefits associated with its former electric generation assets. We believe that the Texas Utility Commission based its order on proposed regulations issued by the IRS in March 2003 which would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of ADITC and EDFIT back to customers. However, in December 2005, the IRS withdrew those proposed normalization regulations and issued new proposed regulations that do not include the provision allowing a retroactive election to pass the tax benefits back to customers. We subsequently requested a PLR asking the IRS whether the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations. In that ruling, which was received in August 2007, the IRS concluded that such reductions would cause normalization violations with respect to the ADITC and EDFIT. As in a similar PLR issued in May 2006 to another Texas utility, the IRS did not reference its proposed regulations.

The district court affirmed the Texas Utility Commission's ruling on the tax normalization issue, but in response to a request from the Texas Utility Commission, the court of appeals ordered that the tax normalization issue be remanded for further consideration. If the Texas Utility Commission's order relating to the ADITC reduction is not reversed or otherwise modified on remand so as to eliminate the normalization violation, the IRS could require us to pay an amount equal to CenterPoint Houston's unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. Such treatment if required by the IRS, could have a material adverse impact on our results of operations, financial condition and cash flows in addition to any potential loss resulting from final resolution of the True-Up Order. However, we and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate or administrative process. Although the Texas Utility Commission has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation, no prediction can be made as to the ultimate action the Texas Utility Commission may take on this issue on remand.

CenterPoint Houston's receivables are concentrated in a small number of REPs, and any delay or default in payment could adversely affect CenterPoint Houston's cash flows, financial condition and results of operations.

CenterPoint Houston's receivables from the distribution of electricity are collected from REPs that supply the electricity CenterPoint Houston distributes to their customers. Currently, CenterPoint Houston does business with 74 REPs. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these retail providers to pay for CenterPoint Houston's services or could cause them to delay such payments. CenterPoint Houston depends on these REPs to remit payments on a timely basis. Applicable regulatory provisions require that customers be shifted to a provider of last resort if a retail electric provider cannot make timely payments. Applicable Texas Utility Commission regulations limit the extent to which CenterPoint Houston can demand security from REPs for payment of its delivery charges. RRI, through its subsidiaries, is CenterPoint Houston's largest customer. Approximately 48% of CenterPoint Houston's $141 million in billed receivables from REPs at December 31, 2007 was owed by subsidiaries of RRI. Any delay or default in payment could adversely affect CenterPoint Houston's cash flows, financial condition and results of operations.

Rate regulation of CenterPoint Houston's business may delay or deny CenterPoint Houston's ability to earn a reasonable return and fully recover its costs.

CenterPoint Houston's rates are regulated by certain municipalities and the Texas Utility Commission based on an analysis of its invested capital and its expenses in a test year. Thus, the rates that CenterPoint Houston is allowed to charge may not match its expenses at any given time. In this connection, pursuant to the Settlement Agreement, discussed in "Business — Regulation — State and Local Regulation — Electric Transmission & Distribution — CenterPoint Houston Rate Agreement" in Item 1 of this report, until June 30, 2010 CenterPoint Houston is limited in its ability to request rate relief. The regulatory process by which rates are determined may not always result in rates that will produce full recovery of CenterPoint Houston's costs and enable CenterPoint Houston to earn a reasonable return on its invested capital.

Disruptions at power generation facilities owned by third parties could interrupt CenterPoint Houston's sales of transmission and distribution services.

CenterPoint Houston transmits and distributes to customers of REPs electric power that the REPs obtain from power generation facilities owned by third parties. CenterPoint Houston does not own or operate any power generation facilities. If power generation is disrupted or if power generation capacity is inadequate, CenterPoint Houston's sales of transmission and distribution services may be diminished or interrupted, and its results of operations, financial condition and cash flows may be adversely affected.

CenterPoint Houston's revenues and results of operations are seasonal.

A significant portion of CenterPoint Houston's revenues is derived from rates that it collects from each retail electric provider based on the amount of electricity it distributes on behalf of such retail electric provider. Thus, CenterPoint Houston's revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues being higher during the warmer months.

Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines and Field Services Businesses

Rate regulation of CERC's business may delay or deny CERC's ability to earn a reasonable return and fully recover its costs.

CERC's rates for its Gas Operations are regulated by certain municipalities and state commissions, and for its interstate pipelines by the FERC, based on an analysis of its invested capital and its expenses in a test year. Thus, the rates that CERC is allowed to charge may not match its 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 CERC's costs and enable CERC to earn a reasonable return on its invested capital.

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

CERC competes 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 CERC 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 CERC's 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 CERC as a result of competition may have an adverse impact on CERC's results of operations, financial condition and cash flows.

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

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

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

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

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

A decline in CERC's credit rating could result in CERC's having to provide collateral in order to purchase gas.

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

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

CERC's interstate pipelines and field services businesses largely rely on natural gas sourced in the various supply basins located in the Mid-continent region of the United States. To the extent the availability of this supply is substantially reduced, it could have an adverse effect on CERC's results of operations, financial condition and cash flows.

CERC's revenues and results of operations are seasonal.

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

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

Subsidiaries of CERC Corp. are involved in significant pipeline construction projects. The construction of new pipelines and related compression facilities requires the expenditure of significant amounts of capital, which may exceed CERC's estimates. These projects may not be completed at the budgeted cost, on schedule or at all. The construction of new pipeline or compression facilities is subject to construction cost overruns due to labor costs,

costs of equipment and materials such as steel and nickel, labor shortages or delays, weather delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. As a result, there is the risk that the new facilities may not be able to achieve CERC's expected investment return, which could adversely affect CERC's financial condition, results of operations or cash flows.

The states in which CERC provides 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 CERC's ability to operate.

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

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

Risk Factors Associated with Our Consolidated Financial Condition

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

As of December 31, 2007, we had $9.7 billion of outstanding indebtedness on a consolidated basis, which includes $2.3 billion of non-recourse transition bonds. As of December 31, 2007, approximately $842 million principal amount of this debt is required to be paid through 2010. This amount excludes principal repayments of approximately $525 million on transition bonds, for which a dedicated revenue stream exists. In addition, as of December 31, 2007, we had $535 million of outstanding 3.75% convertible notes on which holders could exercise their conversion rights during the first quarter of 2008 and in subsequent quarters in which our common stock price causes such notes to be convertible. In January and February 2008, holders of our 3.75% convertible senior notes converted approximately $123 million principal amount of such notes. In February 2008, we issued approximately $488 million of additional non-recourse transition bonds. Our future financing activities may depend, at least in part, on:

- the resolution of the true-up components, including, in particular, the results of appeals to the courts regarding rulings obtained to date;
- 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;
- market expectations regarding our future earnings and cash flows;

- market perceptions of our ability to access capital markets on reasonable terms;
- our exposure to RRI in connection with its indemnification obligations arising in connection with its separation from us; and
- provisions of relevant tax and securities laws.

As of December 31, 2007, CenterPoint Houston had outstanding $2.0 billion aggregate principal amount of general mortgage bonds, including approximately $527 million held in trust to secure pollution control bonds for which we are obligated and approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had outstanding approximately $253 million aggregate principal amount of first mortgage bonds, including approximately $151 million held in trust to secure certain pollution control bonds for which we are obligated. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $2.3 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2007. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

Our current credit ratings are discussed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Sources and Uses of Cash — 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.

As a holding company with no operations of our own, we will depend on distributions from our subsidiaries to meet our payment obligations, and provisions of applicable law or contractual restrictions could limit the amount of those distributions.

We derive all our operating income from, and hold all our assets through, our subsidiaries. As a result, we will 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.

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.

Risks Common to Our Businesses and Other Risks

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

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

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

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

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

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

Our insurance coverage may not be sufficient. Insufficient insurance coverage and increased insurance costs could adversely impact our results of operations, financial condition and cash flows.

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

In common with other companies in its line of business that serve coastal regions, CenterPoint Houston does not have insurance covering its transmission and distribution system because CenterPoint Houston believes it to be cost prohibitive. If CenterPoint Houston were to sustain any loss of, or damage to, its transmission and distribution properties, it may not be able to recover such loss or damage through a change in its regulated rates, and any such recovery may not be timely granted. Therefore, CenterPoint Houston may not be able to restore any loss of, or damage to, any of its transmission and distribution properties without negative impact on its results of operations, financial condition and cash flows.

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

Under some circumstances, we, CenterPoint Houston and CERC could incur liabilities associated with assets and businesses we, CenterPoint Houston and CERC no longer own. These assets and businesses were previously owned by Reliant Energy, a predecessor of CenterPoint Houston, directly or through subsidiaries and include:

- those transferred to RRI or its subsidiaries in connection with the organization and capitalization of RRI prior to its initial public offering in 2001; and
- those transferred to Texas Genco in connection with its organization and capitalization.

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, us and our subsidiaries, including CenterPoint Houston and CERC, with respect to liabilities associated with the transferred assets and businesses. These indemnity provisions were intended to place sole financial responsibility on RRI and its subsidiaries for all liabilities associated with the current and historical businesses and operations of RRI, regardless of the time those liabilities arose. If RRI were unable to satisfy a liability that has been so assumed in circumstances in which Reliant Energy and its subsidiaries were not released from the liability in connection with the transfer, we, CenterPoint Houston or CERC could be responsible for satisfying the liability.

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

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

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

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

In connection with the organization and capitalization of Texas Genco, Texas Genco assumed liabilities associated with the electric generation assets Reliant Energy transferred to it. Texas Genco also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, us and our subsidiaries, including CenterPoint Houston, with respect to liabilities associated with the transferred assets and businesses. In many cases the liabilities assumed were obligations of CenterPoint Houston and CenterPoint Houston was not released by third parties from these liabilities. The indemnity provisions were intended generally to place sole financial responsibility on Texas Genco and its subsidiaries for all liabilities associated with the current and historical businesses and operations of Texas Genco, regardless of the time those liabilities arose. In connection with the sale of Texas Genco's fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC, the separation agreement we entered into with Texas Genco in connection with the organization and capitalization of Texas Genco was amended to provide that all of Texas Genco's rights and obligations under the separation agreement relating to its fossil generation assets, including Texas Genco's obligation to indemnify us with respect to liabilities associated with the fossil generation assets and related business, were assigned to and assumed by Texas Genco LLC. In addition, under the amended separation agreement, Texas Genco is no longer liable for, and we have assumed and agreed to indemnify Texas Genco LLC against, liabilities that Texas Genco originally assumed in connection with its organization to the extent, and only to the extent, that such liabilities are covered by certain insurance policies or other similar agreements held by us. If Texas Genco or Texas Genco LLC were unable to satisfy a liability that had been so assumed or indemnified against, and provided Reliant Energy had not been released from the liability in connection with the transfer, CenterPoint Houston could be responsible for satisfying the liability.

We or our subsidiaries have been named, along with numerous others, as a defendant in lawsuits filed by a large number of individuals who claim injury due to exposure to asbestos. Most claimants in such litigation have been workers who participated in construction of various industrial facilities, including power plants. Some of the claimants have worked at locations we own, but most existing claims relate to facilities previously owned by our subsidiaries but currently owned by Texas Genco LLC, which is now known as NRG Texas LP. We anticipate that additional claims like those received may be asserted in the future. Under the terms of the arrangements regarding separation of the generating business from us and its sale to Texas Genco LLC, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by Texas Genco LLC and its successor, but we have agreed to continue to defend such claims to the extent they are covered by insurance maintained by us, subject to reimbursement of the costs of such defense by Texas Genco LLC.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

Character of Ownership

We own or lease our principal properties in fee, including our corporate office space and various real property. Most of our electric lines and gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

Electric Transmission & Distribution

For information regarding the properties of our Electric Transmission & Distribution business segment, please read "Business — Our Business — Electric Transmission & Distribution — Properties" in Item 1 of this report, which information is incorporated herein by reference.

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.

Other Operations

For information regarding the properties of our Other Operations business segment, please read “Business — Our Business — Other Operations” 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 4 and 10(d) to our consolidated financial statements, which information is incorporated herein by reference.

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

There were no matters submitted to the vote of our security holders during the fourth quarter of 2007.

PART II

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

As of February 15, 2008, our common stock was held of record by approximately 49,092 shareholders. Our common stock is listed on the New York and Chicago Stock Exchanges and is traded under the symbol “CNP.”

The following table sets forth the high and low closing prices of the common stock of CenterPoint Energy on the New York Stock Exchange composite tape during the periods indicated, as reported by *Bloomberg*, and the cash dividends declared in these periods.

	Market Price High	Market Price Low	Dividend Declared per Share
2006			
First Quarter			$ 0.15
January 19	$ 13.28		
March 27		$ 11.92	
Second Quarter			$ 0.15
April 12		$ 11.73	
June 30	$ 12.50		
Third Quarter			$ 0.15
July 3		$ 12.55	
September 1	$ 14.55		
Fourth Quarter			$ 0.15
October 2		$ 14.22	
December 27	$ 16.80		
2007			
First Quarter			$ 0.17
January 18		$ 16.51	
February 26	$ 18.37		
Second Quarter			$ 0.17
May 9	$ 20.02		
June 22		$ 16.90	
Third Quarter			$ 0.17
July 13	$ 17.88		
August 15		$ 15.15	
Fourth Quarter			$ 0.17
October 19		$ 15.97	
November 8	$ 18.51		

The closing market price of our common stock on December 31, 2007 was $17.13 per share.

The amount of future cash dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable contractual restrictions and other factors that our board of directors considers relevant and will be declared at the discretion of the board of directors.

On January 24, 2008, we announced a regular quarterly cash dividend of $0.1825 per share, payable on March 10, 2008 to shareholders of record on February 15, 2008.

Repurchases of Equity Securities

During the quarter ended December 31, 2007, none of our equity securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our “affiliated purchasers,” as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934.

Conversion of 3.75% Convertible Senior Notes due 2023

Since December 31, 2007, we have issued 4,145,377 shares of our common stock upon conversion of approximately $123 million aggregate principal amount of our 3.75% Convertible Senior Notes due 2023, as set forth in the table below:

Settlement Date of Conversion	Principal Amount of Notes Converted	Number of Shares of Common Stock Issued
January 2, 2008	$ 89,056,000	3,005,043(1)
January 3, 2008	5,000,000	168,063(1)
January 7, 2008	4,000	357(2)
January 8, 2008	1,780,000	159,199(2)
January 14, 2008	10,000,000	311,086(1)
January 17, 2008	4,073,000	123,929(1)
January 23, 2008	247,000	7,330(1)
January 24, 2008	12,520,000	370,150(1)
February 5, 2008	4,000	105(1)
February 19, 2008	1,000	89(2)
February 20, 2008	1,000	26(1)
	$ 122,686,000	4,145,377

(1) The number of shares issued in respect of any principal amount of notes converted is in addition to payment of cash in an amount equal to the principal amount of such notes and cash in lieu of fractional shares.

(2) Based on terms of the notes, settled entirely through the issuance of shares except for a payment of cash in lieu of fractional shares.

As a result of a February 2008 conversion election by a holder of $10 million principal amount of our 3.75% Convertible Senior Notes due 2023, additional shares of our common stock are expected to be issued in March 2008 to settle the amount due to the converting holder in excess of the principal amount which must be settled in cash.

The shares of our common stock were issued solely to former holders of our 3.75% Convertible Senior Notes due 2023 upon conversion pursuant to the exemption from registration provided under Section 3(a)(9) of the Securities Act of 1933, as amended. This exemption is available because the shares of our common stock were exchanged by us with our existing security holders exclusively where no commission or other remuneration was paid or given directly or indirectly for soliciting such an exchange.

Common Stock Award to Chairman

In May 2007, we awarded Milton Carroll 25,000 shares of our common stock pursuant to an agreement under which he serves as Chairman of our Board of Directors. We relied on the private placement exemption from registration under Section 4(2) of the Securities Act of 1933.

Item 6. ***Selected Financial Data***

The following table presents selected financial data with respect to our consolidated financial condition and consolidated results of operations and should be read in conjunction with our consolidated financial statements and the related notes in Item 8 of this report.

	Year Ended December 31,				
	2003(1)	2004(2)	2005(3)	2006	2007
	(In millions, except per share amounts)				
Revenues	$ 7,790	$ 7,999	$ 9,722	$ 9,319	$ 9,623
Income from continuing operations before extraordinary item	409	205	225	432	399
Discontinued operations, net of tax	75	(133)	(3)	—	—
Extraordinary item, net of tax	—	(977)	30	—	—
Net income (loss)	$ 484	$ (905)	$ 252	$ 432	$ 399
Basic earnings (loss) per common share:					
Income from continuing operations before extraordinary item	$ 1.35	$ 0.67	$ 0.72	$ 1.39	$ 1.25
Discontinued operations, net of tax	0.24	(0.43)	(0.01)	—	—
Extraordinary item, net of tax	—	(3.18)	0.10	—	—
Basic earnings (loss) per common share	$ 1.59	$ (2.94)	$ 0.81	$ 1.39	$ 1.25
Diluted earnings (loss) per common share:					
Income from continuing operations before extraordinary item	$ 1.24	$ 0.61	$ 0.67	$ 1.33	$ 1.17
Discontinued operations, net of tax	0.22	(0.37)	(0.01)	—	—
Extraordinary item, net of tax	—	(2.72)	0.09	—	—
Diluted earnings (loss) per common share	$ 1.46	$ (2.48)	$ 0.75	$ 1.33	$ 1.17
Cash dividends paid per common share	$ 0.40	$ 0.40	$ 0.40	$ 0.60	$ 0.68
Dividend payout ratio from continuing operations	30%	60%	56%	43%	54%
Return from continuing operations on average common equity	25.7%	14.4%	18.7%	30.3%	23.7%
Ratio of earnings from continuing operations to fixed charges	1.81	1.43	1.51	1.77	1.86
At year-end:					
Book value per common share	$ 5.77	$ 3.59	$ 4.18	$ 4.96	$ 5.61
Market price per common share	9.69	11.30	12.85	16.58	17.13
Market price as a percent of book value	168%	315%	307%	334%	305%
Assets of discontinued operations	$ 4,244	$ 1,565	$ —	$ —	$ —
Total assets	21,461	18,096	17,116	17,633	17,872
Short-term borrowings(4)	63	—	—	187	232
Transition bonds, including current maturities	717	676	2,480	2,407	2,260
Other long-term debt, including current maturities	10,222	8,353	6,427	6,593	7,419
Capitalization:					
Common stock equity	14%	11%	13%	15%	16%
Long-term debt, including current maturities	86%	89%	87%	85%	84%
Capitalization, excluding transition bonds:					
Common stock equity	15%	12%	17%	19%	20%
Long-term debt, excluding transition bonds, including current maturities	85%	88%	83%	81%	80%
Capital expenditures, excluding discontinued operations	$ 497	$ 530	$ 719	$ 1,121	$ 1,011

(1) Net income for 2003 includes the cumulative effect of an accounting change resulting from the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" ($80 million after-tax gain, or $0.26 and $0.24 earnings per basic and diluted share, respectively), which is included in discontinued operations related to Texas Genco Holdings, Inc. (Texas Genco).

(2) Net income for 2004 includes an after-tax extraordinary loss of $977 million ($3.18 and $2.72 loss per basic and diluted share, respectively) based on our analysis of the Public Utility Commission of Texas' (Texas Utility Commission) order in the 2004 True-Up Proceeding. Additionally, we recorded a net after-tax loss of approximately $133 million ($0.43 and $0.37 loss per basic and diluted share, respectively) in 2004 related to our interest in Texas Genco.

(3) Net income for 2005 includes an after-tax extraordinary gain of $30 million ($0.10 and $0.09 per basic and diluted share, respectively) recorded in the first quarter reflecting an adjustment to the extraordinary loss recorded in the last half of 2004 to write down generation-related regulatory assets as a result of the final orders issued by the Texas Utility Commission.

(4) In October 2006, CERC amended its receivables facility. Under the terms of the amended receivables facility, the provisions for sale accounting under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," were no longer met. Accordingly, advances received upon the sale of receivables are accounted for as short-term borrowings as of December 31, 2006 and 2007.

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

The following discussion and analysis should be read in combination with our consolidated financial statements included in Item 8 herein.

OVERVIEW

Background

We are a public utility holding company whose indirect wholly owned subsidiaries include:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in a 5,000-square mile area of the Texas Gulf Coast that includes Houston; and
- CenterPoint Energy Resources Corp. (CERC Corp., and, together with its subsidiaries, CERC), which 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 Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

Business Segments

In this section, we discuss our results from continuing operations on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. We are first and foremost an energy delivery company and it is our intention to remain focused on this segment of the energy business. The results of our business operations are significantly impacted by weather, customer growth, cost management, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to which we are subject. Our electric transmission and distribution services are subject to rate regulation and are reported in the Electric Transmission & Distribution business segment, as are impacts of generation-related stranded costs and other true-up balances recoverable by the regulated electric utility. Our natural gas distribution services are also subject to rate regulation and are reported in the Natural Gas Distribution business segment. A summary of our reportable business segments as of December 31, 2007 is set forth below:

Electric Transmission & Distribution

Our electric transmission and distribution operations provide electric transmission and distribution services to retail electric providers (REPs) serving approximately 2.0 million metered customers in a 5,000-square-mile area of the Texas Gulf Coast that has a population of approximately 5.5 million people and includes Houston.

On behalf of REPs, CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers in locations throughout the control area managed by the Electric Reliability Council of Texas (ERCOT), which serves as the regional reliability coordinating council for member electric power systems in Texas. ERCOT membership is open to consumer groups, investor and municipally owned electric utilities, rural electric cooperatives, independent generators, power marketers and REPs. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation's largest power markets. Transmission and distribution services are provided under tariffs approved by the Texas Utility Commission.

Natural Gas Distribution

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

Competitive Natural Gas Sales and Services

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

Interstate Pipelines

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

Field Services

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

Other Operations

Our other operations business segment includes office buildings and other real estate used in our business operations and other corporate operations which support all of our business operations.

EXECUTIVE SUMMARY

Significant Events in 2007 and 2008

Debt Financing Transactions

In December 2006, we called our 2.875% Convertible Senior Notes due 2024 (2.875% Convertible Notes) for redemption on January 22, 2007 at 100% of their principal amount plus accrued and unpaid interest to the redemption date. The 2.875% Convertible Notes became immediately convertible at the option of the holders upon our call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% Convertible Notes were converted and the remaining amount was redeemed. The $255 million principal amount of the 2.875% Convertible Notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of our common stock.

In February 2007, we redeemed $103 million aggregate principal amount of 8.257% Junior Subordinated Deferrable Interest Debentures at 104.1285% of their aggregate principal amount and the related 8.257% capital securities issued by HL&P Capital Trust II were redeemed at 104.1285% of their $100 million aggregate liquidation value.

In February 2007, we issued $250 million aggregate principal amount of senior notes due in February 2017 with an interest rate of 5.95%. The proceeds from the sale of the senior notes were used to repay debt incurred in satisfying our $255 million cash payment obligation in connection with the conversion and redemption of our 2.875% Convertible Notes as discussed above.

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

In June 2007, we, CenterPoint Houston and CERC Corp. entered into amended and restated bank credit facilities. Our amended credit facility is a $1.2 billion five-year senior unsecured revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on our current credit ratings, versus the previous rate of LIBOR plus 60 basis points. The amended facility at CenterPoint Houston is a $300 million five-year senior unsecured revolving credit facility. The facility's first drawn cost remains at LIBOR plus 45 basis points based on CenterPoint Houston's current credit ratings. The amended facility at CERC Corp. is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility's first drawn cost remains at LIBOR plus 45 basis points based on CERC Corp.'s current credit ratings.

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

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

In 2007, we issued 1.3 million shares of our common stock and paid cash of approximately $40 million upon conversion of approximately $40 million principal amount of our 3.75% convertible senior notes. Subsequent to December 31, 2007, we have issued 4.1 million shares of our common stock and paid cash of approximately $121 million upon conversion of approximately $123 million principal amount of our 3.75% convertible senior notes. A February 2008 conversion notice by a holder of $10 million principal amount of our 3.75% convertible senior notes is expected to result in a March 2008 conversion and settlement with a cash payment for the principal amount and delivery of shares of our common stock for the excess value due the converting holder.

Transition Bonds

Pursuant to a financing order issued by the Texas Utility Commission in September 2007, in February 2008 a subsidiary of CenterPoint Houston issued approximately $488 million in transition bonds in two tranches with interest rates of 4.192% and 5.234% and final maturity dates in February 2020 and February 2023, respectively. Scheduled final payment dates are February 2017 and February 2020. Through issuance of the transition bonds, CenterPoint Houston securitized transition property of approximately $483 million representing the remaining balance of the competition transition charge (CTC) less an environmental refund as reduced by the fuel reconciliation settlement amount.

Recovery of True-Up Balance

In December 2007, the Texas Third Court of Appeals issued its decision in the appeal of the 2004 final order (True-Up Order) issued by the Texas Utility Commission to CenterPoint Houston. In its decision, the court of appeals:

- reversed the district court's judgment to the extent it restored the capacity auction true-up amounts;
- reversed the district court's judgment to the extent it upheld the Texas Utility Commission's decision to allow CenterPoint Houston to recover excess mitigation credits (EMCs) paid to Reliant Energy, Inc. (RRI);
- ordered that the tax normalization issue be remanded to the Texas Utility Commission; and
- affirmed the district court's judgment in all other respects.

CenterPoint Houston and two other parties filed motions for rehearing with the court of appeals. In the event that the motions for rehearing are not resolved in a manner favorable to it, CenterPoint Houston intends to seek further review by the Texas Supreme Court. Although we and CenterPoint Houston believe that CenterPoint Houston's true-up request is consistent with applicable statutes and regulations and accordingly that it is reasonably possible that it will be successful in its further appeals, we can provide no assurance as to the ultimate rulings by the courts on the issues to be considered in the various appeals or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue.

To reflect the impact of the True-Up Order, in 2004 and 2005 we recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in our consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of the pending motions for rehearing or on further review by the Texas Supreme Court, we anticipate that we would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $130 million to $350 million, plus interest subsequent to December 31, 2007.

Interstate Pipeline Expansion

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

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

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

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

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

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

- the resolution of the true-up components, including, in particular, the results of appeals to the courts regarding rulings obtained to date;
- state and federal legislative and regulatory actions or developments, including deregulation, re-regulation, environmental regulations, including regulations related to global climate change, and changes in or application of laws or regulations applicable to the various aspects of our business;
- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;
- cost overruns on major capital projects that cannot be recouped in prices;
- industrial, commercial and residential growth in our service territory and changes in market demand and demographic patterns;
- the timing and extent of changes in commodity prices, particularly natural gas;
- the timing and extent of changes in the supply of natural gas;
- the timing and extent of changes in natural gas basis differentials;
- weather variations and other natural phenomena;
- changes in interest rates or rates of inflation;

- commercial bank and financial market conditions, our access to capital, the cost of such capital, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;
- actions by rating agencies;
- effectiveness of our risk management activities;
- inability of various counterparties to meet their obligations to us;
- non-payment for our services due to financial distress of our customers, including Reliant Energy, Inc. (RRI);
- the ability of RRI and its subsidiaries to satisfy their other 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 our employee benefit plans;
- our potential business strategies, including acquisitions or dispositions of assets or businesses, which we cannot assure will be completed or will have the anticipated benefits to us;
- 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

All dollar amounts in the tables that follow are in millions, except for per share amounts.

	Year Ended December 31, 2005	2006	2007
Revenues	$ 9,722	$ 9,319	$ 9,623
Expenses	8,783	8,274	8,438
Operating Income	939	1,045	1,185
Gain (Loss) on Time Warner Investment	(44)	94	(114)
Gain (Loss) on Indexed Debt Securities	49	(80)	111
Interest and Other Finance Charges	(670)	(470)	(503)
Interest on Transition Bonds	(40)	(130)	(123)
Distribution from AOL Time Warner Litigation Settlement	—	—	32
Additional Distribution to ZENS Holders	—	—	(27)
Return on True-Up Balance	121	—	—
Other Income, net	23	35	33
Income From Continuing Operations Before Income Taxes and Extraordinary Item	378	494	594
Income Tax Expense	(153)	(62)	(195)
Income From Continuing Operations Before Extraordinary Item	225	432	399
Discontinued Operations, net of tax	(3)	—	—
Income Before Extraordinary Item	222	432	399
Extraordinary Item, net of tax	30	—	—
Net Income	$ 252	$ 432	$ 399
Basic Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.72	$ 1.39	$ 1.25
Discontinued Operations, net of tax	(0.01)	—	—
Extraordinary Item, net of tax	0.10	—	—
Net Income	$ 0.81	$ 1.39	$ 1.25
Diluted Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.67	$ 1.33	$ 1.17
Discontinued Operations, net of tax	(0.01)	—	—
Extraordinary Item, net of tax	0.09	—	—
Net Income	$ 0.75	$ 1.33	$ 1.17

2007 Compared to 2006

Income from Continuing Operations. We reported income from continuing operations before extraordinary item of $399 million ($1.17 per diluted share) for 2007 as compared to $432 million ($1.33 per diluted share) for the same period in 2006. As discussed below, the decrease in income from continuing operations of $33 million was primarily due to a $33 million increase in interest expense, excluding transition bond-related interest expense, due to higher borrowing levels; a $133 million increase in income tax expense primarily as a result of the favorable tax settlement reached with the Internal Revenue Service (IRS) in 2006 related to our Zero Premium Exchangeable Subordinated Notes (ZENS) and Automatic Common Exchange Securities (ACES) and an $8 million decrease in operating income from our Electric Transmission & Distribution utility.

These decreases in income from continuing operations were partially offset by a $94 million increase in operating income from our Natural Gas Distribution business segment, a $56 million increase in operating income from our Interstate Pipelines business segment and a $10 million increase in operating income from our Field Services business segment. Segment changes are discussed in detail below.

Income Tax Expense. In 2007, our effective tax rate of 32.8% was lower than the expected statutory tax rate as a result of the revised Texas Franchise Tax Law (Texas Margin Tax) and a Texas state tax examination for tax years 2002 through 2004. Our 2007 effective tax rate differed from the 2006 effective tax rate of 12.6% primarily due to the favorable tax settlement reached with the IRS in 2006 as discussed above.

2006 Compared to 2005

Income from Continuing Operations. We reported income from continuing operations before extraordinary item of $432 million ($1.33 per diluted share) for 2006 as compared to $225 million ($0.67 per diluted share) for the same period in 2005. As discussed below, the increase in income from continuing operations of $207 million was primarily due to a $200 million decrease in interest expense, excluding transition bond-related interest expense, due to lower borrowing costs and borrowing levels; a $91 million decrease in income tax expense primarily related to the tax settlement associated with ZENS and ACES; a $19 million increase in operating income from our Field Services business segment; a $17 million increase in operating income from our Competitive Natural Gas Sales and Services business segment; and a $16 million increase in operating income from our Interstate Pipelines business segment.

These increases in income from continuing operations were partially offset by a $121 million decrease in other income related to a reduction in the return on the true-up balance of our Electric Transmission & Distribution business segment recorded in 2005 and a $51 million decrease in operating income from our Natural Gas Distribution business segment. Segment changes are discussed in detail below.

Net income for 2005 included an after-tax extraordinary gain of $30 million ($0.09 per diluted share) reflecting an adjustment to the extraordinary loss recorded in 2004 to write down generation-related regulatory assets as a result of the final orders issued by the Texas Utility Commission.

Income Tax Expense. The effective tax rate in 2006 was reduced to 12.6% primarily as a result of an agreement with the IRS related to the ZENS and ACES which reduced accrued tax and related interest reserves by approximately $107 million. The net reduction in the reserves related to ZENS and ACES in 2006 was $92 million. In addition, we reached tentative settlements with the IRS on a number of other tax matters which allowed us to reduce our total tax and related interest reserve for other tax items from $60 million at December 31, 2005 to $34 million at December 31, 2006.

Interest Expense and Other Finance Charges

Total interest expense incurred was $711 million, $600 million and $626 million in 2005, 2006 and 2007, respectively. During the fourth quarter of 2005, CenterPoint Houston retired at maturity its $1.341 billion term loan, which bore interest at LIBOR plus 975 basis points, subject to a minimum LIBOR rate of 3%. Borrowings under a CenterPoint Houston credit facility, which bore interest at LIBOR plus 75 basis points, were used for the payment of the term loan and then repaid with a portion of the proceeds of the December 2005 issuance of transition bonds.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for 2005, 2006 and 2007. Included in revenues are 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,		
	2005	2006	2007
Electric Transmission & Distribution	$ 487	$ 576	$ 561
Natural Gas Distribution	175	124	218
Competitive Natural Gas Sales and Services	60	77	75
Interstate Pipelines	165	181	237
Field Services	70	89	99
Other Operations	(18)	(2)	(5)
Total Consolidated Operating Income	$ 939	$ 1,045	$ 1,185

Electric Transmission & Distribution

The following tables provide summary data of our Electric Transmission & Distribution business segment, CenterPoint Houston, for 2005, 2006 and 2007 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2005	2006	2007
Revenues:			
Electric transmission and distribution utility	$ 1,538	$ 1,516	$ 1,560
Transition bond companies	106	265	277
Total revenues	1,644	1,781	1,837
Expenses:			
Operation and maintenance, excluding transition bond companies	618	611	652
Depreciation and amortization, excluding transition bond companies	258	243	243
Taxes other than income taxes	214	212	223
Transition bond companies	67	139	158
Total expenses	1,157	1,205	1,276
Operating Income	$ 487	$ 576	$ 561
Operating Income:			
Electric transmission and distribution operations	$ 429	$ 395	$ 400
Competition transition charge	19	55	42
Transition bond companies(1)	39	126	119
Total segment operating income	$ 487	$ 576	$ 561
Throughput (in gigawatt-hours (GWh)):			
Residential	24,924	23,955	23,999
Total	74,189	75,877	76,291
Average number of metered customers:			
Residential	1,683,100	1,732,656	1,773,319
Total	1,912,346	1,968,114	2,012,636

(1) Represents the amount necessary to pay interest on the transition bonds.

2007 Compared to 2006. Our Electric Transmission & Distribution business segment reported operating income of $561 million for 2007, consisting of $400 million from our regulated electric transmission and distribution utility operations (TDU), $42 million from the CTC, and $119 million related to transition bond companies. For 2006, operating income totaled $576 million, consisting of $395 million from the TDU, $55 million from the CTC, and $126 million related to transition bond companies. Revenues increased due to growth ($22 million), with over 53,000 metered customers added since December 2006, higher transmission-related revenues ($22 million), increased miscellaneous service charges ($15 million), increased demand ($7 million), interest on settlement of the final fuel reconciliation ($4 million) and a one-time charge in the second quarter of 2006 related to the resolution of the unbundled cost of service order ($32 million). These increases were partially offset by the rate reduction resulting from the 2006 rate case settlement that was implemented in October 2006 ($41 million) and lower CTC return resulting from the reduction in the allowed interest rate on the unrecovered CTC balance from 11.07% to 8.06% in 2006 ($13 million). Operation and maintenance expense increased primarily due to higher transmission costs ($25 million), the absence of a gain on the sale of property in 2006 ($13 million), and increased expenses primarily related to low income and energy efficiency programs as required by the 2006 rate case settlement ($8 million), partially offset by settlement of the final fuel reconciliation ($13 million).

2006 Compared to 2005. Our Electric Transmission & Distribution business segment reported operating income of $576 million for 2006, consisting of $395 million from the TDU, $55 million from the CTC and $126 million related to the transition bond companies. For 2005, operating income totaled $487 million, consisting of $429 million for the TDU, $19 million from the CTC, and $39 million related to the transition bond companies. Increases in operating income from growth ($34 million), a higher CTC amount collected in 2006 ($36 million), revenues from ancillary services ($11 million) and proceeds from land sales ($13 million) were partially offset by milder weather and reduced demand ($49 million), and the implementation of reduced base rates ($13 million) and spending on low income assistance and energy efficiency programs ($5 million) resulting from the Settlement Agreement described in "Business — Our Business — Regulation — State and Local Regulation — Electric Transmission & Distribution — CenterPoint Houston Rate Agreement." In addition, the TDU's operating income for 2006 included the $32 million adverse impact of the resolution of the remand of the 2001 UCOS order.

In September 2005, CenterPoint Houston's service area in Texas was adversely affected by Hurricane Rita. Although damage to CenterPoint Houston's electric facilities was limited, over 700,000 customers lost power at the height of the storm. Power was restored to over a half million customers within 36 hours and all power was restored in less than five days. The Electric Transmission & Distribution business segment's revenues lost as a result of the storm were more than offset by warmer than normal weather during the third quarter of 2005. CenterPoint Houston deferred $28 million of restoration costs which are being amortized over a seven-year period that began in October 2006.

Natural Gas Distribution

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

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

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

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

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

Competitive Natural Gas Sales and Services

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

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

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

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

Interstate Pipelines

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

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

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

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

Field Services

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

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

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

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

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

Other Operations

The following table provides summary data for our Other Operations business segment for 2005, 2006 and 2007 (in millions):

	Year Ended December 31,		
	2005	2006	2007
Revenues	$ 19	$ 15	$ 10
Expenses	37	17	15
Operating Loss	$ (18)	$ (2)	$ (5)

2007 Compared to 2006. Our Other Operations business segment's operating loss in 2007 compared to 2006 increased by $3 million.

2006 Compared to 2005. Our Other Operations business segment's operating loss in 2006 compared to 2005 decreased $16 million primarily due to increased rental revenues ($2 million), decreased insurance costs ($4 million), and decreased state franchise taxes ($8 million).

Discontinued Operations

In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco, whose principal remaining asset was its ownership interest in a nuclear generating facility, distributed $2.231 billion in cash to us. The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to us of $700 million, was completed in April 2005. We recorded an after-tax loss of $3 million for the year ended December 31, 2005 related to the operations of Texas Genco.

The consolidated financial statements report the businesses described above as discontinued operations for all periods presented in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144).

For further information regarding discontinued operations, please read Note 3 to our consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flow

The net cash provided by (used in) operating, investing and financing activities for 2005, 2006 and 2007 is as follows (in millions):

	Year Ended December 31,		
	2005	2006	2007
Cash provided by (used in):			
Operating activities	$ 63	$ 991	$ 774
Investing activities	17	(1,056)	(1,300)
Financing activities	(171)	118	528

Cash Provided by Operating Activities

Net cash provided by operating activities in 2007 decreased $217 million compared to 2006 primarily due to the timing of fuel recovery ($204 million), increased tax payments ($10 million), increased interest payments ($40 million), increased gas storage inventory ($36 million) and decreased net accounts receivable/payable ($178 million). These decreases were partially offset by decreased reductions in customer margin deposit requirements ($76 million) and decreases in our margin deposit requirements ($145 million).

Net cash provided by operating activities in 2006 increased $928 million compared to 2005 primarily due to decreased tax payments of $156 million, the majority of which related to the tax payment in the first quarter of 2005 associated with the sale of our former electric generation business (Texas Genco); increased fuel over-recovery ($240 million) primarily related to declining gas prices during 2006; decreases in net regulatory assets ($271 million), primarily due to the termination of excess mitigation credits effective April 2005 and recovery of regulatory assets through rates; increased net accounts receivable/payable ($128 million) primarily due to decreased gas prices as compared to 2005 partially offset by funding under CERC's receivables facility being accounted for as short-term borrowings instead of sales of receivables beginning in October 2006 and decreased cash used in the operations of Texas Genco ($38 million). Additionally, customer margin deposit requirements decreased ($155 million) primarily due to the decline in natural gas prices from December 2005 and our margin deposits increased ($52 million).

Cash Provided by (Used in) Investing Activities

Net cash used in investing activities increased $244 million in 2007 as compared to 2006 due to increased capital expenditures of $107 million primarily related to pipeline projects for our Interstate Pipelines business segment, increased notes receivable from unconsolidated affiliates of $148 million and increased investment in unconsolidated affiliates of $26 million, primarily related to the SESH pipeline project.

Net cash used in investing activities increased $1.1 billion in 2006 as compared to 2005 primarily due to increased capital expenditures of $314 million primarily related to our Electric Transmission & Distribution, Interstate Pipelines, and Field Services business segments, increased restricted cash of transition bond companies of $36 million primarily related to the $1.85 billion of transition bonds issued in December 2005 and the absence of

$700 million in proceeds received in the second quarter of 2005 from the sale of our remaining interest in Texas Genco and cash of Texas Genco of $24 million.

Cash Provided by (Used in) Financing Activities

Net cash provided by financing activities in 2007 increased $410 million compared to 2006 primarily due to increased borrowings under revolving credit facilities ($334 million) and increased proceeds from long-term debt ($576 million), which were partially offset by increased repayments of long-term debt ($319 million), increased dividend payments ($31 million) and decreased short-term borrowings ($142 million).

Net cash provided by financing activities in 2006 increased $289 million compared to 2005 primarily due to net proceeds from the issuance of long-term debt of $324 million, decreased repayments of borrowings under our revolving credit facility ($236 million) and funding under CERC's receivables facility being accounted for as short-term borrowings ($187 million) in 2006, partially offset by the absence of borrowings under Texas Genco's revolving credit facility ($75 million) due to the sale of Texas Genco, payments of long-term debt ($229 million) and increased dividend payments of $63 million.

Future Sources and Uses of Cash

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 regulatory actions. Our principal cash requirements for 2008 include the following:

- approximately $995 million of capital expenditures;
- cash settlement obligations in connection with possible conversions by holders of our 3.75% convertible senior notes, having an aggregate principal amount of $535 million at December 31, 2007;
- maturing long-term debt aggregating approximately $666 million, including $159 million of transition bonds;
- investment in and advances to SESH of approximately $294 million;
- dividend payments on CenterPoint Energy common stock and interest payments on debt.

We expect that borrowings under our credit facilities, the proceeds from the issuance of $488 million of transition bonds in February 2008 (discussed below) and anticipated cash flows from operations will be sufficient to meet our cash needs in 2008. Cash needs or discretionary financing or refinancing may also result in the issuance of equity or debt securities in the capital markets.

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

	2007	2008	2009	2010	2011	2012
Electric Transmission & Distribution	$ 401	$ 371	$ 358	$ 444	$ 415	$ 392
Natural Gas Distribution	191	209	192	193	196	203
Competitive Natural Gas Sales and Services	7	18	2	2	2	2
Interstate Pipelines	308	209	133	77	72	76
Field Services	74	154	83	93	94	85
Other Operations	30	34	29	38	22	20
Total	$ 1,011	$ 995	$ 797	$ 847	$ 801	$ 778

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

Contractual Obligations	Total	2008	2009-2010	2011-2012	2013 and thereafter
Transition bond debt	$ 2,260	$ 159	$ 366	$ 432	$ 1,303
Other long-term debt(1)	7,419	1,156	212	986	5,065
Interest payments — transition bond debt(2)	745	117	207	166	255
Interest payments — other long-term debt(2)	4,215	420	793	688	2,314
Short-term borrowings	232	232	—	—	—
Capital leases	1	—	—	—	1
Operating leases(3)	68	19	22	13	14
Benefit obligations(4)	—	—	—	—	—
Purchase obligations(5)	27	27	—	—	—
Non-trading derivative liabilities	75	61	14	—	—
Other commodity commitments(6)	3,027	743	563	550	1,171
Joint venture obligations(7)	294	294	—	—	—
Income taxes(8)	118	118	—	—	—
Total contractual cash obligations	$ 18,481	$ 3,346	$ 2,177	$ 2,835	$ 10,123

(1) 2008 maturities include $114 million of ZENS obligations as they are exchangeable for cash at any time at the option of the holders and $535 million principal amount of our 3.75% convertible senior notes as they meet the criteria that make them eligible for conversion at the option of the holders of these notes.

(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, 2007. 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 10(b) to our consolidated financial statements.

(4) Contributions to our qualified pension plan are not required in 2008. However, we expect to contribute approximately $8 million and $21 million, respectively, to our non-qualified pension and postretirement benefits plans in 2008.

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

(6) For a discussion of other commodity commitments, please read Note 10(a) to our consolidated financial statements.

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

(8) Represents estimated income tax liability for settled positions for tax years under examination. In addition, as of December 31, 2007, the liability for uncertain income tax positions was $82 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 these liabilities might be paid.

Transition Bonds. During the 2007 legislative session, the Texas legislature amended certain statutes authorizing amounts that can be securitized by utilities. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of the remaining balance of the CTC, as well as the fuel reconciliation settlement amount, provisions for deduction of the environmental refund and certain other matters. CenterPoint Houston reached substantial agreement with other parties to this proceeding, and a financing order was approved by the Texas Utility Commission in September 2007. The financing order allowed for the netting of the fuel reconciliation settlement amount against the environmental refund. In February 2008, approximately $488 million of transition bonds were issued by a new special purpose subsidiary of CenterPoint Houston pursuant to the financing order. Proceeds were used by the special purpose entity to purchase $483 million of transition property from CenterPoint Houston and to pay costs of issuance. Following a subsequent distribution to us, we used the proceeds for general corporate purposes, including the repayment of debt and the making of loans to or investments in affiliates.

Convertible Debt. As of December 31, 2007, the 3.75% convertible senior notes discussed in Note 8(b) to our consolidated financial statements have been included as current portion of long-term debt in our Consolidated Balance Sheets because the last reported sale price of our common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the third quarter of 2007 was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, during the fourth quarter of 2007, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes. In 2007, we issued 1.3 million shares of our common stock and paid cash of approximately $40 million upon conversion of approximately $40 million principal amount of our 3.75% convertible senior notes. Subsequent to December 31, 2007, we have issued 4.1 million shares of our common stock and paid cash of approximately $121 million upon conversion of approximately $123 million principal amount of our 3.75% convertible senior notes. A February 2008 conversion notice by a holder of $10 million principal amount of our 3.75% convertible senior notes is expected to result in a March 2008 conversion and settlement with a cash payment for the principal amount and delivery of shares of our common stock for the excess value due the converting holder.

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

The APSC's revised rules impose record keeping, record access, employee training and reporting requirements related to affiliate transactions, including notification to the APSC of the formation of new affiliates that will engage in transactions with the utility and annual certification by the utility's president or chief executive officer and its chief financial officer of compliance with the rules. In addition, the revised rules require a report to the APSC in the event the utility's bond rating is downgraded in certain circumstances. Although the revised rules impose new requirements on CERC's operations in Arkansas, at this time neither we nor CERC anticipate that the revised rules will have an adverse effect on existing operations in Arkansas. In September 2007, Gas Operations made a filing with the APSC in accordance with the revised rules to document existing practices that would be covered by grandfathering provisions of those rules.

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

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

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

Senior Notes. In February 2007, we issued $250 million aggregate principal amount of senior notes due in February 2017 with an interest rate of 5.95%. The proceeds from the sale of the senior notes were used to repay debt incurred in satisfying our $255 million cash payment obligation in connection with the conversion and redemption of our 2.875% Convertible Notes.

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

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

Credit and Receivables Facilities. In June 2007, we, CenterPoint Houston and CERC Corp. entered into amended and restated bank credit facilities. Our amended credit facility is a $1.2 billion five-year senior unsecured revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on our current credit ratings, versus the previous rate of LIBOR plus 60 basis points. The facility contains covenants, including a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant.

The amended facility at CenterPoint Houston is a $300 million five-year senior unsecured revolving credit facility. The facility' first drawn cost remains at LIBOR plus 45 basis points based on CenterPoint Houston's current credit ratings. The facility contains covenants, including a debt (excluding transition bonds) to total capitalization covenant.

The amended facility at CERC Corp. is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility's first drawn cost remains at LIBOR plus 45 basis points based on CERC Corp.'s current credit ratings. The facility contains covenants, including a debt to total capitalization covenant.

Under each of the credit facilities, an additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on the borrower's credit rating. Borrowings under each of the facilities are subject to customary terms and conditions. However, there is no requirement that we, CenterPoint Houston or CERC Corp. 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 each of the credit facilities are subject to acceleration upon the occurrence of events of default that we, CenterPoint Houston or CERC Corp. consider customary.

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

We, CenterPoint Houston and CERC Corp. are currently in compliance with the various business and financial covenants contained in the respective receivables and credit facilities.

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

Date Executed	Company	Type of Facility	Size of Facility	Amount Utilized at February 15, 2008	Termination Date
June 29, 2007	CenterPoint Energy	Revolver	$ 1,200	$ 28(1)	June 29, 2012
June 29, 2007	CenterPoint Houston	Revolver	300	4(1)	June 29, 2012
June 29, 2007	CERC Corp.	Revolver	950	87(2)	June 29, 2012
October 30, 2007	CERC	Receivables	375	85	October 28, 2008

(1) Represents outstanding letters of credit.

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

The $1.2 billion CenterPoint Energy credit facility backstops a $1.0 billion commercial paper program under which we began issuing commercial paper in June 2005. The $950 million CERC Corp. credit facility backstops a $950 million commercial paper program under which CERC Corp. began issuing commercial paper in February 2008. As of December 31, 2007, there was no commercial paper outstanding. The CenterPoint Energy commercial paper is rated "Not Prime" by Moody's Investors Service, Inc. (Moody's), "A-2" by Standard & Poor's Rating Services (S&P), a division of The McGraw-Hill Companies, and "F3" by Fitch, Inc. (Fitch). The CERC Corp. commercial paper is rated "P-3" by Moody's, "A-2" by S&P, and "F2" by Fitch. As a result of the credit ratings on the two commercial paper programs, we do not expect to be able to rely on the sale of commercial paper to fund all of our short-term borrowing requirements. We cannot assure you that these ratings, or the credit ratings set forth below in "— Impact on Liquidity of a Downgrade in Credit Ratings," will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing, the cost of such financings and the execution of our commercial strategies.

Securities Registered with the SEC. As of December 31, 2007, CenterPoint Energy had a shelf registration statement covering senior debt securities, preferred stock and common stock aggregating $750 million and CERC Corp. had a shelf registration statement covering $400 million principal amount of senior debt securities.

Hedging of Future Debt Issuances. As of February 15, 2008, we had outstanding Treasury rate lock agreements with an aggregate notional amount of $300 million, expiration dates of June 2008 and a weighted-average locked Treasury rate on ten-year debt of 4.05%. These agreements were executed to hedge the ten-year Treasury rate expected to be used in pricing a 2008 issuance of ten-year notes.

Temporary Investments. As of December 31, 2007, we had no external temporary investments.

Money Pool. We have a money pool through which the holding company and participating subsidiaries 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 our revolving credit facility or the sale of our commercial paper.

Impact on Liquidity of a Downgrade in Credit Ratings. As of February 15, 2008, Moody's, S&P, and Fitch had assigned the following credit ratings to senior debt of CenterPoint Energy and certain subsidiaries:

	Moody's		S&P		Fitch	
Company/Instrument	Rating	Outlook(1)	Rating	Outlook(2)	Rating	Outlook(3)
CenterPoint Energy Senior Unsecured Debt	Ba1	Stable	BBB-	Positive	BBB-	Stable
CenterPoint Houston Senior Secured Debt (First Mortgage Bonds)	Baa2	Stable	BBB+	Positive	A-	Stable
CERC Corp. Senior Unsecured Debt	Baa3	Stable	BBB	Positive	BBB	Stable

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

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

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

A decline in credit ratings could increase borrowing costs under our $1.2 billion credit facility, CenterPoint Houston's $300 million credit facility and CERC Corp.'s $950 million credit facility. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments.

In September 1999, we issued 2.0% ZENS having an original principal amount of $1.0 billion of which $840 million remain outstanding. Each ZENS note is exchangeable at the holder's option at any time for an amount of cash equal to 95% of the market value of the reference shares of Time Warner Inc. common stock (TW Common) attributable to each ZENS note. If our creditworthiness were to drop such that ZENS note holders thought our liquidity was adversely affected or the market for the ZENS notes were to become illiquid, some ZENS note holders might decide to exchange their ZENS notes for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of TW Common that we own or from other sources. We own shares of TW Common equal to approximately 100% of the reference shares used to calculate our obligation to the holders of the ZENS notes. ZENS note exchanges result in a cash outflow because deferred tax liabilities related to the ZENS notes and TW Common shares become current tax obligations when ZENS notes are exchanged or otherwise retired and TW Common shares are sold. A tax obligation of approximately $153 million relating to our "original issue discount" deductions on the ZENS would have been payable if all of the ZENS had been exchanged for cash on December 31, 2007. The ultimate tax obligation related to the ZENS notes continues to increase by the amount of the tax benefit realized each year and there could be a significant cash outflow when the taxes are paid as a result of the retirement of the ZENS notes.

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

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

Cross Defaults. Under our revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $50 million by us or any of our significant subsidiaries will cause a default. In addition, six outstanding series of our senior notes, aggregating $1.4 billion in principal amount as of December 31, 2007, provide that a payment default by us, CERC Corp. or CenterPoint Houston 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 subsidiaries' debt instruments or bank credit facilities.

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

- cash collateral requirements that could exist in connection with certain contracts, including gas purchases, gas price and weather hedging and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, particularly given gas price levels and volatility;
- acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of natural gas suppliers;
- increased costs related to the acquisition of natural gas;
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various regulatory actions;
- the ability of RRI and its subsidiaries to satisfy their obligations as the principal customers of CenterPoint Houston and in respect of RRI's indemnity obligations to us and our subsidiaries or in connection with the contractual obligations to a third party pursuant to which CERC is a guarantor;
- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- cash payments in connection with the exercise of contingent conversion rights of holders of convertible debt;
- the outcome of litigation brought by and against us;
- contributions to benefit plans;
- restoration costs and revenue losses resulting from natural disasters such as hurricanes; and
- various other risks identified in "Risk Factors" in Item 1A of this report.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money. CenterPoint Houston's credit facility limits CenterPoint Houston's debt (excluding transition bonds) as a percentage of its total capitalization to 65%. CERC Corp.'s bank facility and its receivables facility limit CERC's debt as a percentage of its total capitalization to 65%. Our $1.2 billion credit facility contains a debt, excluding transition bonds, to EBITDA covenant. Additionally, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

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.

Accounting for Rate Regulation

SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation” (SFAS No. 71), 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 Electric Transmission & Distribution business applies SFAS No. 71, which results in our accounting for the regulatory effects of recovery of stranded costs and other regulatory assets resulting from the unbundling of the transmission and distribution business from our former electric generation operations in our consolidated financial statements. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Significant accounting estimates embedded within the application of SFAS No. 71 with respect to our Electric Transmission & Distribution business segment relate to $281 million of recoverable electric generation-related regulatory assets as of December 31, 2007. These costs are recoverable under the provisions of the 1999 Texas Electric Choice Plan. Based on our analysis of the final order issued by the Texas Utility Commission, we recorded an after-tax charge to earnings in 2004 of approximately $977 million to write down our electric generation-related regulatory assets to their realizable value, which was reflected as an extraordinary loss. Based on subsequent orders received from the Texas Utility Commission, we recorded an extraordinary gain of $30 million after-tax in 2005 related to the regulatory asset. Additionally, a district court in Travis County, Texas issued a judgment which would have had the effect of restoring approximately $650 million, plus interest, of disallowed costs. CenterPoint Houston and other parties appealed the district court’s judgment to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court’s judgment to the extent it restored the capacity auction true-up amounts;
- reversed the district court’s judgment to the extent it upheld the Texas Utility Commission’s decision to allow CenterPoint Houston to recover EMCs paid to RRI;
- ordered that the tax normalization issue be remanded to the Texas Utility Commission; and
- affirmed the district court’s judgment in all other respects.

CenterPoint Houston and two other parties filed motions for rehearing with the court of appeals. In the event that the motions for rehearing are not resolved in a manner favorable to it, CenterPoint Houston intends to seek further review by the Texas Supreme Court. Although we and CenterPoint Houston believe that CenterPoint Houston's true-up request is consistent with applicable statutes and regulations and accordingly that it is reasonably possible that it will be successful in its further appeals, we can provide no assurance as to the ultimate rulings by the courts on the issues to be considered in the various appeals or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue.

To reflect the impact of the True-Up Order, in 2004 and 2005 we recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in our consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of the pending motions for rehearing or on further review by the Texas Supreme Court, we anticipate that we would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $130 million to $350 million, plus interest subsequent to December 31, 2007.

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 SFAS No. 142, "Goodwill and Other Intangible Assets." No impairment of goodwill was indicated based on our annual analysis as of July 1, 2007. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of our assets and result in an impairment charge.

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

Asset Retirement Obligations

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

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

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

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 3.0%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by approximately the same percentage. At December 31, 2007, our estimated cost of retiring these assets is approximately $81 million.

Unbilled Energy Revenues

Revenues related to electricity delivery and 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 electricity delivery revenue is estimated each month based on daily supply volumes, applicable rates and analyses reflecting significant historical trends and experience. 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.

Pension and Other Retirement Plans

We sponsor pension and other retirement plans in various forms covering all employees who meet eligibility requirements. We use several statistical and other factors that attempt to anticipate future events in calculating the expense and liability related to our plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. Please read "— Other Significant Matters — Pension Plans" for further discussion.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(o) to our consolidated financial statements for a discussion of new accounting pronouncements that affect us.

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 2(p) to our consolidated financial statements, we maintain a non-contributory qualified pension plan covering substantially all employees. Employer contributions for the qualified plan are based on actuarial computations that establish the minimum contribution required under the Employee Retirement Income Security Act of 1974 (ERISA) and the maximum deductible contribution for income tax purposes.

Under the terms of our pension plan, we reserve the right to change, modify or terminate the plan. Our funding policy is to review amounts annually and contribute an amount at least equal to the minimum contribution required under ERISA and the Internal Revenue Code.

We made no contribution to the qualified pension plans in 2006 and 2007. The minimum funding requirements for these plans did not require contribution for the respective years.

Additionally, we maintain an unfunded non-qualified benefit restoration plan that allows participants to retain the benefits to which they would have been entitled under our non-contributory pension plan except for the federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. Employer contributions for the non-qualified benefit restoration plan represent benefit payments made to participants and totaled $7 million and $9 million in 2006 and 2007, respectively.

In accordance with SFAS No. 87, "Employers' Accounting for Pensions," changes in pension obligations and assets may not be immediately recognized as pension expense in the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension expense recorded in any period may not reflect the actual level of benefit payments provided to plan participants.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158). SFAS No. 158 requires us, as the sponsor of a plan, to (a) recognize on our balance sheets as an asset a plan's over-funded status or as a liability such plan's under-funded status, (b) measure a plan's assets and obligations as of the end of our fiscal year and (c) recognize changes in the funded status of our plans in the year that changes occur through adjustments to other comprehensive income.

As a result of the adoption of SFAS No. 158 as of December 31, 2006, we recorded a regulatory asset of $466 million and a charge to accumulated comprehensive income of $79 million, net of tax.

At December 31, 2007, the market value of plan assets exceeded the projected benefit obligation of our pension plans by $147 million. Changes in interest rates and the market values of the securities held by the plan during 2008 could materially, positively or negatively, change our funded status and affect the level of pension expense and required contributions.

Pension expense was $36 million, $46 million and $15 million for 2005, 2006 and 2007, respectively. In addition, included in the costs for 2005 is less than $1 million of expense related to Texas Genco participants. Pension expense for Texas Genco participants is reflected in our Statement of Consolidated Income as discontinued operations.

The calculation of pension expense and related liabilities requires the use of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. Two of the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate.

As of December 31, 2007, our qualified pension plan had an expected long-term rate of return on plan assets of 8.5%, which was unchanged from the rate assumed as of December 31, 2006. We believe that our actual asset allocation, on average, will approximate the targeted allocation and the estimated return on net assets. We regularly review our actual asset allocation and periodically rebalance plan assets as appropriate.

As of December 31, 2007, the projected benefit obligation was calculated assuming a discount rate of 6.40%, which is a 0.55% increase from the 5.85% discount rate assumed in 2006. The discount rate was determined by reviewing yields on high-quality bonds that receive one of the two highest ratings given by a recognized rating agency and the expected duration of pension obligations specific to the characteristics of our plan.

Pension expense for 2008, including the benefit restoration plan, is estimated to be $1 million based on an expected return on plan assets of 8.5% and a discount rate of 6.40% as of December 31, 2007. If the expected return assumption were lowered by 0.5% (from 8.5% to 8.0%), 2008 pension expense would increase by approximately $9 million.

As of December 31, 2007, pension plan assets exceed the projected benefit obligation (including the unfunded benefit restoration plan) by $147 million. However, if the discount rate was lowered by 0.5% (from 6.40% to 5.90%), the assumption change would increase our projected benefit obligation and 2008 pension expense by approximately $103 million and $10 million, respectively. In addition, the assumption change would impact our Consolidated Balance Sheet by increasing the regulatory asset recorded as of December 31, 2007 by $79 million and would result in a charge to comprehensive income in 2007 of $15 million, net of tax.

Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plan will impact our future pension expense and liabilities. We cannot predict with certainty what these factors will be.

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

Impact of Changes in Interest Rates and Energy Commodity Prices

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

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

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

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

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

Interest Rate Risk

As of December 31, 2007, we had outstanding long-term debt, bank loans, lease obligations, treasury rate lock derivative instruments and our obligations under our ZENS that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $187 million and $563 million at December 31, 2006 and 2007, respectively. If the floating interest rates were to increase by 10% from December 31, 2007 rates, our combined interest expense would increase by approximately $3 million annually.

At December 31, 2006 and 2007, we had outstanding fixed-rate debt (excluding indexed debt securities) and trust preferred securities aggregating $8.9 billion and $9.2 billion, respectively, in principal amount and having a fair value of $9.6 billion and $9.7 billion, respectively. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Note 8 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $352 million if interest rates were to decline by 10% from their levels at December 31, 2007. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity.

As of December 31, 2007, we had treasury rate lock derivative instruments with $150 million of notional value and expiration dates of June 2, 2008 to hedge the risk of changes in the 10-year U.S. treasury rate prior to the forecasted issuance of fixed-rate debt in 2008. As of December 31, 2007, the treasury lock derivative instruments could be terminated at a cost of $2 million. The treasury rate lock derivative instruments qualify as cash flow hedges under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” (SFAS No. 133), and are marked to market in our Consolidated Balance Sheets with changes reflected in accumulated other comprehensive income. A decrease of 10% in the December 31, 2007 level of interest rates on 10-year U.S. treasury notes would increase the cost of terminating the treasury rate locks outstanding at December 31, 2007 by approximately $5 million.

As discussed in Note 6 to our consolidated financial statements, upon adoption of SFAS No. 133, effective January 1, 2001, the ZENS obligation was bifurcated into a debt component and a derivative component. The debt component of $114 million at December 31, 2007 was a fixed-rate obligation and, therefore, did not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by approximately $18 million if interest rates were to decline by 10% from levels at December 31, 2007. Changes in the fair value of the derivative component, a $261 million recorded liability at December 31, 2007, are recorded in our Statements of Consolidated Income and, therefore, we are exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from December 31, 2007 levels, the fair value of the derivative component liability would increase by approximately $4 million, which would be recorded as an unrealized loss in our Statements of Consolidated Income.

Equity Market Value Risk

We are exposed to equity market value risk through our ownership of 21.6 million shares of TW Common, which we hold to facilitate our ability to meet our obligations under the ZENS. Please read Note 6 to our consolidated financial statements for a discussion of the effect of adoption of SFAS No. 133 on our ZENS obligation and our historical accounting treatment of our ZENS obligation. A decrease of 10% from the December 31, 2007 market value of TW Common would result in a net loss of approximately $4 million, which would be recorded as an unrealized loss in our Statements of Consolidated Income.

Commodity Price Risk From Non-Trading Activities

We use derivative instruments as economic hedges to offset the commodity price exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in fair value based on a hypothetical 10% movement in energy prices. At December 31, 2007, the recorded fair value of our non-trading energy derivatives was a net liability of $25 million. The net liability consisted of an $8 million net liability associated with price stabilization activities of our Natural Gas Distribution business segment and a net liability of $17 million related to our Competitive Natural Gas Sales and Services business segment. Net assets or liabilities related to the price stabilization activities correspond directly with net over/under recovered gas cost liabilities or assets on the balance sheet. An increase of 10% in the market prices of energy commodities from their December 31, 2007 levels would have increased the fair value of our non-trading energy derivatives net liability by $5 million.

The above analysis of the non-trading energy derivatives utilized for commodity price risk management purposes does not include the favorable impact that the same hypothetical price movement would have on our physical purchases and sales of natural gas to which the hedges relate. Furthermore, the non-trading energy derivative portfolio is managed to complement the physical transaction portfolio, reducing overall risks within limits. Therefore, the adverse impact to the fair value of the portfolio of non-trading energy derivatives held for hedging purposes associated with the hypothetical changes in commodity prices referenced above is expected to be substantially offset by a favorable impact on the underlying hedged physical transactions.

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
CenterPoint Energy, Inc.
Houston, Texas

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

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

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

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106 and 132(R)", effective December 31, 2006. Also, as discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations", effective December 31, 2005.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008, expressed an unqualified opinion on the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
CenterPoint Energy, Inc.
Houston, Texas

We have audited the internal control over financial reporting of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report of Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2007, of the Company and our report dated February 28, 2008, expressed an unqualified opinion on those financial statements.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2008

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2007 which is included herein on page 64.

/s/ DAVID M. MCCLANAHAN

President and Chief Executive Officer

/s/ GRAY L. WHITLOCK

Executive Vice President and Chief Financial Officer

February 28, 2008

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31, 2005	2006	2007
	(In millions, except for share amounts)		
Revenues	$ 9,722	$ 9,319	$ 9,623
Expenses:			
Natural gas	6,509	5,909	5,995
Operation and maintenance	1,358	1,399	1,440
Depreciation and amortization	541	599	631
Taxes other than income taxes	375	367	372
Total	8,783	8,274	8,438
Operating Income	939	1,045	1,185
Other Income (Expense):			
Gain (loss) on Time Warner investment	(44)	94	(114)
Gain (loss) on indexed debt securities	49	(80)	111
Interest and other finance charges	(670)	(470)	(503)
Interest on transition bonds	(40)	(130)	(123)
Distribution from AOL Time Warner litigation settlement	—	—	32
Additional distribution to ZENS holders	—	—	(27)
Return on true-up balance	121	—	—
Other, net	23	35	33
Total	(561)	(551)	(591)
Income From Continuing Operations Before Income Taxes and Extraordinary Item	378	494	594
Income tax expense	(153)	(62)	(195)
Income From Continuing Operations Before Extraordinary Item	225	432	399
Discontinued Operations:			
Income from Texas Genco, net of tax	11	—	—
Loss on disposal of Texas Genco, net of tax	(14)	—	—
Total	(3)	—	—
Income Before Extraordinary Item	222	432	399
Extraordinary item, net of tax	30	—	—
Net Income	$ 252	$ 432	$ 399
Basic Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.72	$ 1.39	$ 1.25
Discontinued Operations, net of tax	(0.01)	—	—
Extraordinary item, net of tax	0.10	—	—
Net Income	$ 0.81	$ 1.39	$ 1.25
Diluted Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.67	$ 1.33	$ 1.17
Discontinued Operations, net of tax	(0.01)	—	—
Extraordinary item, net of tax	0.09	—	—
Net Income	$ 0.75	$ 1.33	$ 1.17

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31, 2005	2006 (In millions)	2007
Net income	$ 252	$ 432	$ 399
Other comprehensive income, net of tax:			
SFAS No. 158 adjustment (net of tax of $28)	—	—	34
Minimum pension liability adjustment (net of tax of ($5) and $6)	(9)	12	—
Net deferred gain from cash flow hedges (net of tax of $9, $11, and $6)	17	22	11
Reclassification of deferred loss (gain) from cash flow hedges realized in net income (net of tax of $6, $8, and ($14))	11	14	(20)
Other comprehensive income from discontinued operations (net of tax of $2)	3	—	—
Other comprehensive income	22	48	25
Comprehensive income	$ 274	$ 480	$ 424

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2007
	(In millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 127	$ 129
Investment in Time Warner common stock	471	357
Accounts receivable, net	1,017	910
Accrued unbilled revenues	451	558
Inventory	399	490
Non-trading derivative assets	98	38
Prepaid expense and other current assets	432	306
Total current assets	2,995	2,788
Property, Plant and Equipment, net	9,204	9,740
Other Assets:		
Goodwill	1,705	1,696
Regulatory assets	3,290	2,993
Non-trading derivative assets	21	11
Notes receivable from unconsolidated affiliates	—	148
Other	418	496
Total other assets	5,434	5,344
Total Assets	$ 17,633	$ 17,872
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Short-term borrowings	$ 187	$ 232
Current portion of long-term debt	1,198	1,315
Indexed debt securities derivative	372	261
Accounts payable	1,010	726
Taxes accrued	364	316
Interest accrued	159	170
Non-trading derivative liabilities	141	61
Accumulated deferred income taxes, net	316	350
Other	474	360
Total current liabilities	4,221	3,791
Other Liabilities:		
Accumulated deferred income taxes, net	2,323	2,235
Unamortized investment tax credits	39	31
Non-trading derivative liabilities	80	14
Benefit obligations	545	499
Regulatory liabilities	792	828
Other	275	300
Total other liabilities	4,054	3,907
Long-term Debt	7,802	8,364
Commitments and Contingencies (Note 10)		
Shareholders' Equity	1,556	1,810
Total Liabilities and Shareholders' Equity	$ 17,633	$ 17,872

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2005	2006	2007
		(In millions)	
Cash Flows from Operating Activities:			
Net income	$ 252	$ 432	$ 399
Discontinued operations, net of tax	3	—	—
Extraordinary item, net of tax	(30)	—	—
Income from continuing operations and cumulative effect of accounting change	225	432	399
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	541	599	631
Amortization of deferred financing costs	77	56	65
Deferred income taxes	232	(234)	8
Tax and interest reserves reductions related to ZENS and ACES settlement	—	(107)	—
Investment tax credit	(8)	(7)	(8)
Unrealized loss (gain) on Time Warner investment	44	(94)	114
Unrealized loss (gain) on indexed debt securities	(49)	80	(111)
Write-down of natural gas inventory	—	66	11
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(456)	262	—
Inventory	(115)	(82)	(102)
Taxes receivable	(53)	53	—
Accounts payable	321	(269)	(185)
Fuel cost over (under) recovery/surcharge	(129)	111	(93)
Non-trading derivatives, net	(12)	(18)	11
Margin deposits, net	51	(156)	65
Interest and taxes accrued	(471)	230	(33)
Net regulatory assets and liabilities	(192)	79	81
Pension contribution	(75)	—	—
Other current assets	(14)	(76)	13
Other current liabilities	69	18	(20)
Other assets	30	43	(33)
Other liabilities	67	6	(51)
Other, net	18	(1)	12
Net cash provided by operating activities of continuing operations	101	991	774
Net cash used in operating activities of discontinued operations	(38)	—	—
Net cash provided by operating activities	63	991	774
Cash Flows from Investing Activities:			
Capital expenditures	(693)	(1,007)	(1,114)
Proceeds from sale of Texas Genco	700	—	—
Purchase of minority interest of Texas Genco	(383)	—	—
Decrease in restricted cash for purchase of minority interest of Texas Genco	383	—	—
Increase in cash of Texas Genco	24	—	—
Increase in restricted cash of transition bond companies	(12)	(32)	(1)
Increase in notes receivable from unconsolidated affiliates	—	—	(148)
Investment in unconsolidated affiliates	—	(13)	(39)
Other, net	(2)	(4)	2
Net cash provided by (used in) investing activities	17	(1,056)	(1,300)
Cash Flows from Financing Activities:			
Increase in short-term borrowings, net	75	187	45
Long-term revolving credit facility, net	(236)	(3)	331
Proceeds from long-term debt	3,161	324	900
Payments of long-term debt	(3,045)	(229)	(548)
Debt issuance costs	(21)	(5)	(9)
Payment of common stock dividends	(124)	(187)	(218)
Proceeds from issuance of common stock, net	17	27	22
Other, net	2	4	5
Net cash provided by (used in) financing activities	(171)	118	528
Net Increase (Decrease) in Cash and Cash Equivalents	(91)	53	2
Cash and Cash Equivalents at Beginning of Year	165	74	127
Cash and Cash Equivalents at End of Year	$ 74	$ 127	$ 129
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 667	$ 532	$ 572
Income taxes (refunds), net	351	195	205
Non-cash transactions:			
Increase in accounts payable related to capital expenditures	35	113	—

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED SHAREHOLDERS' EQUITY

	2005		2006		2007	
	Shares	Amount	Shares	Amount	Shares	Amount
	(In millions of dollars and shares)					
Preference Stock, none outstanding	—	$ —	—	$ —	—	$ —
Cumulative Preferred Stock, $0.01 par value; authorized 20,000,000 shares, none outstanding	—	—	—	—	—	—
Common Stock, $0.01 par value; authorized 1,000,000,000 shares						
Balance, beginning of year	308	3	310	3	314	3
Issuances related to benefit and investment plans	2	—	4	—	2	—
Issuances related to convertible debt conversions	—	—	—	—	7	—
Balance, end of year	310	3	314	3	323	3
Additional Paid-in-Capital						
Balance, beginning of year	—	2,891	—	2,931	—	2,977
Issuances related to benefit and investment plans	—	40	—	46	—	46
Balance, end of year	—	2,931	—	2,977	—	3,023
Accumulated Deficit						
Balance, beginning of year		(1,728)		(1,600)		(1,355)
Net income		252		432		399
Cumulative effect of adopting FIN 48		—		—		2
Common stock dividends — $0.40 per share in 2005, $0.60 per share in 2006, and $0.68 per share in 2007		(124)		(187)		(218)
Balance, end of year		(1,600)		(1,355)		(1,172)
Accumulated Other Comprehensive Loss						
Balance, end of year:						
SFAS No. 158 incremental effect		—		(79)		(45)
Minimum pension liability adjustment		(15)		(3)		(3)
Net deferred gain (loss) from cash flow hedges		(23)		13		4
Total accumulated other comprehensive loss, end of year		(38)		(69)		(44)
Total Shareholders' Equity		$ 1,296		$ 1,556		$ 1,810

See Notes to the Company's Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

(a) Background

CenterPoint Energy, Inc. (the Company) is a public utility holding company. The Company's operating subsidiaries own and operate electric transmission and distribution facilities, natural gas distribution facilities, interstate pipelines and natural gas gathering, processing and treating facilities. As of December 31, 2007, the Company's indirect wholly owned subsidiaries included:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in a 5,000-square mile area of the Texas Gulf Coast that includes Houston; and
- CenterPoint Energy Resources Corp. (CERC Corp., and, together with its subsidiaries, CERC), which owns and operates natural gas distribution systems in six states. Subsidiaries of CERC own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A wholly owned subsidiary of CERC Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

(b) Basis of Presentation

The Company sold the fossil generation assets of Texas Genco Holdings, Inc. (Texas Genco) in December 2004 and completed the sale of Texas Genco, which had continued to own an interest in a nuclear generating facility, in April 2005.

The consolidated financial statements report the businesses described above as discontinued operations for all periods presented in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144).

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

(c) Revenues

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

(d) Long-lived Assets and Intangibles

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

	Weighted Average Useful Lives (Years)	December 31, 2006	December 31, 2007
		(In millions)	
Electric Transmission & Distribution	27	$ 6,823	$ 6,993
Natural Gas Distribution	31	2,875	3,065
Competitive Natural Gas Sales and Services	24	53	59
Interstate Pipelines	57	1,943	2,194
Field Services	51	429	493
Other property	30	444	446
Total		12,567	13,250
Accumulated depreciation and amortization:			
Electric Transmission & Distribution		2,566	2,602
Natural Gas Distribution		462	590
Competitive Natural Gas Sales and Services		9	9
Interstate Pipelines		176	160
Field Services		31	29
Other property		119	120
Total accumulated depreciation and amortization		3,363	3,510
Property, plant and equipment, net		$ 9,204	$ 9,740

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

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

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

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

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

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

(e) Regulatory Assets and Liabilities

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

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

	December 31, 2006	December 31, 2007
	(In millions)	
Electric generation-related regulatory assets(1)	$ 343	$ 325
Securitized regulatory asset	2,285	2,131
Unamortized loss on reacquired debt	85	79
Pension and postretirement-related regulatory asset(2)	483	360
Other long-term regulatory assets	94	98
Total regulatory assets	3,290	2,993
Electric generation-related regulatory liabilities	39	44
Estimated removal costs	697	734
Other long-term regulatory liabilities	56	50
Total regulatory liabilities	792	828
Total regulatory assets and liabilities, net	$ 2,498	$ 2,165

(1) Excludes $234 million and $220 million of allowed equity return on the true-up balance as of December 31, 2006 and 2007, respectively.

(2) Upon adoption of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158), the

Company recorded a regulatory asset for its unrecognized costs associated with operations that have historically recovered and currently recover pension and postretirement expenses in rates.

If events were to occur that would make the recovery of these assets and liabilities no longer probable, the Company would be required to write off or write down these regulatory assets and liabilities. During 2004, the Company wrote-off net regulatory assets of $1.5 billion ($977 million after-tax) as an extraordinary loss in response to the Public Utility Commission of Texas' (Texas Utility Commission) order on CenterPoint Houston's final true-up application. Based on subsequent orders received from the Texas Utility Commission, the Company recorded an extraordinary gain of $47 million ($30 million after-tax) in the second quarter of 2005 related to these regulatory assets. For further discussion of regulatory assets, see Note 4.

The Company's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2006 and 2007, these removal costs of $697 million and $734 million, respectively, are classified as regulatory liabilities in the Company's Consolidated Balance Sheets. A portion of the amount of removal costs that relate to asset retirement obligations have been reclassified from a regulatory liability to an asset retirement liability in accordance with Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47).

(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. See Notes 2(e) and 4(a) for additional discussion of these items.

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

	2005	2006	2007
Depreciation expense	$ 432	$ 440	$ 455
Amortization expense	109	159	176
Total depreciation and amortization expense	$ 541	$ 599	$ 631

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

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for subsidiaries that apply SFAS No. 71. Interest and AFUDC for subsidiaries that apply SFAS No. 71 are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During 2005, 2006 and 2007, the Company capitalized interest and AFUDC of $4 million, $10 million and $21 million, respectively.

(h) Income Taxes

The Company files a consolidated federal income tax return and follows a policy of comprehensive interperiod tax allocation. The Company uses the asset and liability method of accounting for deferred income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes". Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Investment tax credits that were deferred are being amortized over the estimated lives of the related property. A valuation allowance is established against deferred tax assets for which management believes realization is not considered more likely than not.

Prior to 2007, the Company evaluated uncertain income tax positions and recorded a tax liability for those positions that management believed were probable of an unfavorable outcome and could be reasonably estimated. Effective January 1, 2007, the Company accounts for the tax effects of uncertain income tax positions in accordance with FIN 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109" (FIN 48). The Company recognizes interest and penalties as a component of income tax expense. For additional information regarding income taxes, see Note 9.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $33 million and $38 million at December 31, 2006 and 2007, respectively. The provision for doubtful accounts in the Company's Statements of Consolidated Income for 2005, 2006 and 2007 was $40 million, $35 million and $45 million, respectively.

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

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

(j) Inventory

Inventory consists principally of materials and supplies and natural gas. Materials and supplies are valued at the lower of average cost or market. Natural gas inventories of the Company's Competitive Natural Gas Sales and Services business segment are also primarily valued at the lower of average cost or market. Natural gas inventories of the Company's Natural Gas Distribution business segment are primarily valued at weighted average cost. During 2006 and 2007, the Company recorded $66 million and $11 million, respectively, in write-downs of natural gas inventory to the lower of average cost or market.

	December 31, 2006	December 31, 2007
	(In millions)	
Materials and supplies	$ 94	$ 95
Natural gas	305	395
Total inventory	$ 399	$ 490

(k) Derivative Instruments

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

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

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

(l) Investment in Other Debt and Equity Securities

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

As of December 31, 2006 and 2007, the Company held an investment in Time Warner Inc. (TW) common stock (TW Common), which was classified as a "trading" security. For information regarding this investment, see Note 6.

(m) Environmental Costs

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

(n) Statements of Consolidated Cash Flows

For purposes of reporting cash flows, the Company considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. In connection with the issuance of transition bonds in October 2001 and December 2005, the Company was required to establish restricted cash accounts to collateralize the bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the bonds. Cash and cash equivalents does not include restricted cash of $49 million at both December 31, 2006 and 2007. For additional information regarding transition bonds, see Notes 4(a) and 8(b). Cash and cash equivalents includes $123 million and $128 million at December 31, 2006 and 2007, respectively, that is held by the Company's transition bond subsidiaries solely to support servicing the transition bonds.

(o) New Accounting Pronouncements

In July 2006, the FASB issued FIN 48 which clarifies the accounting for uncertain income tax positions and requires the Company to recognize management's best estimate of the impact of a tax position if it is considered "more likely than not," as defined in SFAS No. 5, "Accounting for Contingencies," of being sustained on audit based solely on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The cumulative effect of adopting FIN 48 as of January 1, 2007 was a credit of $2 million to accumulated deficit.

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

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

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

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

(p) Stock-Based Incentive Compensation Plans and Employee Benefit Plans

Stock-Based Incentive Compensation Plans

The Company has long-term incentive compensation plans (LICPs) that provide for the issuance of stock-based incentives, including performance-based shares, performance-based units, restricted shares and stock options to officers and key employees. A maximum of approximately 36 million shares of CenterPoint Energy common stock is authorized to be issued under these plans.

Equity awards are granted to employees without cost to the participants. The performance shares are distributed based upon the achievement of certain objectives over a three-year performance cycle. The stock awards granted in 2005, 2006 and 2007 are subject to the operational condition that total common dividends declared during the three-year vesting period must be at least $1.20, $1.80 and $2.04 per share, respectively. The stock awards vest at the end of a three-year period. Upon vesting, both the performance shares and the stock awards are issued to the participants along with the value of dividend equivalents earned over the performance cycle or vesting period.

Option awards are generally granted with an exercise price equal to the average of the high and low sales price of the Company's stock at the date of grant. These option awards generally become exercisable in one-third increments on each of the first through third anniversaries of the grant date and have 10-year contractual terms. No options were granted during 2005, 2006 and 2007.

The Company recorded LICP compensation expense of $13 million, $10 million and $10 million in 2005, 2006 and 2007, respectively.

The total income tax benefit recognized related to such arrangements was $5 million, $4 million and $4 million in 2005, 2006 and 2007, respectively. No compensation cost related to such arrangements was capitalized as a part of inventory or fixed assets in 2005, 2006 or 2007.

Compensation costs for performance shares and stock awards granted under the LICPs are measured using fair value and expected achievement levels on the grant date. Forfeitures are estimated on the date of grant and are adjusted as required through the remaining vesting period.

The following tables summarize the Company's LICP activity for 2007:

Stock Options

	Outstanding Options Year Ended December 31, 2007			
	Shares (Thousands)	Weighted-Average Exercise Price	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2006	9,573	$ 17.15		
Forfeited or expired	(890)	25.02		
Exercised	(1,913)	11.24		
Outstanding at December 31, 2007	6,770	17.78	3.2	$ 27
Exercisable at December 31, 2007	6,770	17.78	3.2	27

	Non-Vested Options Year Ended December 31, 2007	
	Shares (Thousands)	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2006	566	$ 1.86
Vested	(560)	1.86
Forfeited or expired	(6)	1.86
Outstanding at December 31, 2007	—	—

Performance Shares

	Outstanding and Non-Vested Shares Year Ended December 31, 2007			
	Shares (Thousands)	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2006	1,703			$ 12.60
Granted	659			18.20
Forfeited	(146)			13.57
Vested and released to participants	(84)			13.79
Outstanding at December 31, 2007	2,132	0.9	$ 24	14.21

The non-vested and outstanding shares displayed in the above tables assume that shares are issued at the maximum performance level (150%). The aggregate intrinsic value reflects the impacts of current expectations of achievement and stock price.

Performance-Based Units

	Outstanding and Non-Vested Units Year Ended December 31, 2007			
	Units (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2006	31	$ 100.00		
Forfeited	—	100.00		
Vested and released to participants	(31)	100.00		
Outstanding at December 31, 2007	—	—	—	$ —

Stock Awards

	Outstanding and Non-Vested Shares Year Ended December 31, 2007			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2006	753	$ 12.14		
Granted	245	18.29		
Forfeited	(58)	13.27		
Vested and released to participants	(220)	11.14		
Outstanding at December 31, 2007	720	14.45	1.2	$ 12

The weighted-average grant-date fair values of awards granted were as follows for 2005, 2006 and 2007:

	Year Ended December 31,		
	2005	2006	2007
Performance shares	$ 12.13	$ 13.05	$ 18.20
Stock awards	12.25	12.96	18.29

The total intrinsic value of awards received by participants was as follows for 2005, 2006 and 2007:

	Year Ended December 31,		
	2005	2006 (In millions)	2007
Options exercised	$ 8	$ 10	$ 13
Performance shares	5	10	—
Performance units	—	—	3
Stock awards	—	7	4

As of December 31, 2007 there was $21 million of total unrecognized compensation cost related to non-vested LICP arrangements. That cost is expected to be recognized over a weighted-average period of 1.7 years.

Cash received from LICPs was $9 million, $17 million and $22 million for 2005, 2006 and 2007, respectively.

The actual tax benefit realized for tax deductions related to LICPs totaled $5 million, $11 million and $7 million, for 2005, 2006 and 2007, respectively.

The Company has a policy of issuing new shares in order to satisfy share-based payments related to LICPs.

Pension and Postretirement Benefits

The Company maintains a non-contributory qualified defined benefit plan covering substantially all employees, with benefits determined using a cash balance formula. Under the cash balance formula, participants accumulate a retirement benefit based upon 4% of eligible earnings and accrued interest. Prior to 1999, the pension plan accrued benefits based on years of service, final average pay and covered compensation. 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. Participants have historically been 100% vested in their benefit after completing five years of service. Effective January 1, 2008, the Company changed the vesting schedule to provide for 100% vesting after three years to comply with the Pension Protection Act of 2006. In addition to the non-contributory qualified defined benefit plan, the Company maintains a non-qualified benefit restoration plan which allows participants to receive the benefits to which they would have been entitled under the Company'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 Company provides certain healthcare and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Under plan amendments, effective in early 1999, healthcare benefits for future retirees were changed to limit employer contributions for medical coverage.

Such benefit costs are accrued over the active service period of employees. The net unrecognized transition obligation, resulting from the implementation of accrual accounting, is being amortized over approximately 20 years.

On January 5, 2006, the Company offered a Voluntary Early Retirement Program (VERP) to approximately 200 employees who were age 55 or older with at least five years of service as of February 28, 2006. The election period was from January 5, 2006 through February 28, 2006. For those electing to accept the VERP, three years of age and service were added to their qualified pension plan benefit and three years of service were added to their postretirement benefit. The one-time additional pension and postretirement expense of $9 million is reflected in the table below as a benefit enhancement.

The Company's net periodic cost includes the following components relating to pension, including the benefit restoration plan, and postretirement benefits:

	Year Ended December 31,					
	2005		2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)					
Service cost	$ 35	$ 2	$ 37	$ 2	$ 37	$ 2
Interest cost	99	27	101	26	100	26
Expected return on plan assets	(137)	(12)	(143)	(12)	(149)	(12)
Amortization of prior service cost	(7)	2	(7)	2	(7)	—
Amortization of net loss	46	—	50	—	34	3
Amortization of transition obligation	—	7	—	7	—	7
Benefit enhancement	—	—	8	1	—	—
Other	—	1	—	—	—	—
Net periodic cost	$ 36	$ 27	$ 46	$ 26	$ 15	$ 26

The Company used the following assumptions to determine net periodic cost relating to pension and postretirement benefits:

	December 31,					
	2005		2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Discount rate	5.75%	5.75%	5.70%	5.70%	5.85%	5.85%
Expected return on plan assets	8.50	8.00	8.50	8.00	8.50	7.60
Rate of increase in compensation levels	4.60	—	4.60	—	4.60	—

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

The following table summarizes changes in the benefit obligation, plan assets, the amounts recognized in consolidated balance sheets and the key assumptions of our pension, including benefit restoration, and postretirement plans. The measurement dates for plan assets and obligations were December 31, 2006 and 2007.

	December 31,			
	2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)			
Change in Benefit Obligation				
Benefit obligation, beginning of year	$ 1,830	$ 467	$ 1,776	$ 469
Service cost	37	2	37	2
Interest cost	101	26	100	26
Participant contributions	—	6	—	5
Benefits paid	(161)	(42)	(145)	(35)
Actuarial gain	(39)	(3)	(123)	(33)
Plan amendment	—	8	—	—
Medicare reimbursement	—	4	—	3
Benefit enhancement	8	1	—	—
Benefit obligation, end of year	1,776	469	1,645	437
Change in Plan Assets				
Plan assets, beginning of year	1,729	154	1,806	158
Employer contributions	7	27	9	22
Participant contributions	—	6	—	5
Benefits paid	(161)	(42)	(145)	(35)
Actual investment return	231	13	122	11
Plan assets, end of year	1,806	158	1,792	161
Funded status, end of year	$ 30	$ (311)	$ 147	$ (276)

	December 31,			
	2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)			
Amounts Recognized in Balance Sheets				
Other assets-other	$ 109	$ —	$ 231	$ —
Current liabilities-other	(7)	(8)	(8)	(8)
Other liabilities-benefit obligations	(72)	(303)	(76)	(268)
Net asset (liability), end of year	$ 30	$ (311)	$ 147	$ (276)
Actuarial Assumptions				
Discount rate	5.85%	5.85%	6.40%	6.40%
Expected return on plan assets	8.50	7.60	8.50	7.60
Rate of increase in compensation levels	4.60	—	5.75	—
Healthcare cost trend rate assumed for the next year	—	7.00	—	7.00
Prescription drug cost trend rate assumed for the next year	—	13.00	—	13.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	—	5.50	—	5.50
Year that the healthcare rate reaches the ultimate trend rate	—	2011	—	2012
Year that the prescription drug rate reaches the ultimate trend rate	—	2014	—	2015

The accumulated benefit obligation for all defined benefit pension plans was $1,719 million and $1,623 million as of December 31, 2006 and 2007, respectively.

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

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

For measurement purposes, healthcare costs are assumed to increase 7% during 2008, after which this rate decreases until reaching the ultimate trend rate of 5.5% in 2012. Prescription drug costs are assumed to increase 13% during 2008, after which this rate decreases until reaching the ultimate trend rate of 5.5% in 2015.

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

	December 31,			
	2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)			
Unrecognized actuarial loss (gain)	$ 128	$ 8	$ 99	$ (4)
Unrecognized prior service cost (credit)	(7)	16	(6)	14
Unrecognized transition obligation	—	4	—	4
Net amount recognized in other comprehensive income	$ 121	$ 28	$ 93	$ 14

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

	Pension Benefits	Postretirement Benefits
Net loss (gain)	$ (20)	$ (11)
Amortization of net loss	(9)	—
Amortization of prior service credit (cost)	1	(2)
Amortization of transition obligation	—	(1)
Total recognized in comprehensive income	$ (28)	$ (14)

The total recognized in net periodic costs and other comprehensive income was a benefit of $13 million and an expense of $12 million for pension and postretirement benefits, respectively, for the year ended December 31, 2007.

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

	Pension Benefits	Postretirement Benefits
Unrecognized actuarial loss	$ 15	$ —
Unrecognized transition obligation	—	1
Unrecognized prior service cost (credit)	(1)	2
Amounts in comprehensive income to be recognized in net periodic cost in 2008	$ 14	$ 3

The following table displays pension benefits related to the Company's non-qualified benefits restoration plan that have accumulated benefit obligations in excess of plan assets:

	December 31,	
	2006	2007
	(In millions)	
Accumulated benefit obligation	$ 78	$ 82
Projected benefit obligation	79	84
Plan assets	—	—

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

	1% Increase	1% Decrease
	(In millions)	
Effect on the postretirement benefit obligation	$ 19	$ 16
Effect on total of service and interest cost	1	1

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

	December 31,			
	2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Domestic equity securities	50%	28%	49%	26%
Global equity securities	11	—	11	—
International equity securities	10	11	12	9
Debt securities	27	61	27	64
Real estate	1	—	1	—
Cash	1	—	—	1
Total	100%	100%	100%	100%

In managing the investments associated with the benefit plans, the Company's objective is to preserve and enhance the value of plan assets while maintaining an acceptable level of volatility. These objectives are expected to be achieved through an investment strategy 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, the Company has adopted and maintains the following weighted average allocation targets for its benefit plans:

	Pension Benefits	Postretirement Benefits
Domestic equity securities	25-35%	22-32%
Global equity securities	7-13%	—
International equity securities	17-23%	4-14%
Debt securities	30-40%	60-70%
Real estate	0-5%	—
Cash	0-2%	0-2%

The asset allocation targets in the table above reflect changes approved by the Company's Benefits Committee during 2007 that were implemented in January 2008.

The pension plan did not include any holdings of CenterPoint Energy common stock as of December 31, 2006 or 2007.

The Company contributed $9 million and $22 million to its non-qualified pension and postretirement benefits plans in 2007, respectively. The Company expects to contribute approximately $8 million and $21 million to its non-qualified pension and postretirement benefits plans in 2008, respectively.

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

		Postretirement Benefit Plan	
	Pension Benefits	Benefit Payments	Medicare Subsidy Receipts
2008	$ 123	$ 32	$ (4)
2009	127	33	(4)
2010	130	34	(4)
2011	131	36	(4)
2012	134	37	(5)
2013-2017	680	199	(28)

Savings Plan

The Company has a qualified employee savings plan that includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended (the Code), and an employee stock ownership plan (ESOP) under Section 4975(e)(7) of the Code. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 16% of compensation. The Company matches 75% of the first 6% of each employee's compensation contributed. The Company may contribute an additional discretionary match of up to 50% of the first 6% of each employee's compensation contributed. These matching contributions are fully vested at all times.

Participating employees may elect to invest all or a portion of their contributions to the plan in CenterPoint Energy common stock, to have dividends reinvested in additional shares or to receive dividend payments in cash on any investment in CenterPoint Energy common stock, and to transfer all or part of their investment in CenterPoint Energy common stock to other investment options offered by the plan.

The savings plan has significant holdings of CenterPoint Energy common stock. As of December 31, 2007, an aggregate of 20,511,903 shares of CenterPoint Energy's common stock were held by the savings plan, which represented 24.8% of its investments. Given the concentration of the investments in CenterPoint Energy's common stock, the savings plan and its participants have market risk related to this investment.

The Company's savings plan benefit expense was $35 million, $34 million and $35 million in 2005, 2006 and 2007, respectively. Included in the 2005 amount is less than $1 million savings plan benefit expense related to Texas Genco participants. Amounts for Texas Genco's participants are reflected as discontinued operations in the Statements of Consolidated Income.

Postemployment Benefits

Net postemployment benefit costs 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) were $8 million and $6 million in 2005 and 2006, respectively. The Company recorded postemployment benefit income of $2 million in 2007.

Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2006 and 2007 was $43 million and $37 million, respectively, relating to postemployment obligations.

Other Non-Qualified Plans

The Company has non-qualified deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of the Company. During 2005, 2006 and 2007, the Company recorded benefit expense relating to these plans of $8 million, $6 million and $7 million, respectively. Included in “Benefit Obligations” in the accompanying Consolidated Balance Sheets at December 31, 2006 and 2007 was $105 million and $100 million, respectively, relating to deferred compensation plans.

Change in Control Agreements and Other Employee Matters

Effective January 1, 2007, the Company entered into agreements with certain of its officers that generally provide, to the extent applicable, in the case of a change in control of the Company and termination of employment, for severance benefits of up to three times annual base salary plus bonus, and other benefits. By their terms, these agreements are for a one-year term with automatic renewal unless action is taken by the Board prior to the renewal. Effective January 1, 2008, these agreements were amended in minor respects.

As of December 31, 2007, approximately 30% of the Company’s employees are subject to collective bargaining agreements. The Company has four collective bargaining agreements, (1) United Steel Workers (USW) Local 13-227, (2) Office and Professional Employees International Union (OPEIU) Local 12 Metro, (3) OPEIU Local 12 Mankato, and (4) USW Local 13-1, that are scheduled to expire in 2008 that collectively cover approximately 8% of its employees. The Company has a good relationship with these bargaining units and expects to renegotiate new agreements in 2008.

(3) Discontinued Operations

In July 2004, the Company announced its agreement to sell Texas Genco to Texas Genco LLC. In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco’s principal remaining asset was its ownership interest in the South Texas Project Electric Generating Station, a nuclear generating facility. The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to the Company of $700 million, was completed in April 2005.

The following table summarizes the components of the loss from discontinued operations of Texas Genco for the year ended December 31, 2005 (in millions):

Texas Genco net income as reported	$ 10
Adjustment for general corporate overhead reclassification, net of tax(1)	1
Income from discontinued operations of Texas Genco, net of tax and minority interest	11
Loss on sale of Texas Genco, net of tax	(4)
Loss offsetting Texas Genco’s earnings, net of tax	(10)
Loss on disposal of Texas Genco, net of tax	(14)
Total Discontinued Operations of Texas Genco	$ (3)

(1) General corporate overhead previously allocated to Texas Genco from CenterPoint Energy, which will not be eliminated by the sale of Texas Genco, was excluded from income from discontinued operations and is reflected as general corporate overhead of CenterPoint Energy in income from continuing operations in accordance with SFAS No. 144.

Revenues related to Texas Genco included in discontinued operations for the year ended December 31, 2005 were $62 million. Income from these discontinued operations for the year ended December 31, 2005 is reported net of income tax expense of $4 million.

(4) Regulatory Matters

(a) Recovery of True-Up Balance

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas Electric Choice Plan (Texas electric restructuring law). In December 2004, the Texas Utility Commission issued its final order (True-Up Order) allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and provided for adjustment of the amount to be recovered to include interest on the balance until recovery, along with the principal portion of additional excess mitigation credits (EMCs) returned to customers after August 31, 2004 and in certain other respects.

CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, that court issued its judgment on the various appeals. In its judgment, the district court:

- reversed the Texas Utility Commission's ruling that had denied recovery of a portion of the capacity auction true-up amounts;
- reversed the Texas Utility Commission's ruling that precluded CenterPoint Houston from recovering the interest component of the EMCs paid to retail electric providers; and
- affirmed the True-Up Order in all other respects.

The district court's decision would have had the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston's initial request.

CenterPoint Houston and other parties appealed the district court's judgment to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court's judgment to the extent it restored the capacity auction true-up amounts;
- reversed the district court's judgment to the extent it upheld the Texas Utility Commission's decision to allow CenterPoint Houston to recover EMCs paid to Reliant Energy, Inc. (RRI);
- ordered that the tax normalization issue described below be remanded to the Texas Utility Commission; and
- affirmed the district court's judgment in all other respects.

CenterPoint Houston and two other parties filed motions for rehearing with the court of appeals. In the event that the motions for rehearing are not resolved in a manner favorable to it, CenterPoint Houston intends to seek further review by the Texas Supreme Court. Although the Company and CenterPoint Houston believe that CenterPoint Houston's true-up request is consistent with applicable statutes and regulations and accordingly that it is reasonably possible that it will be successful in its further appeals, the Company can provide no assurance as to the ultimate rulings by the courts on the issues to be considered in the various appeals or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue described below.

To reflect the impact of the True-Up Order, in 2004 and 2005 the Company recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in the Company's consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of the pending motions for rehearing or on further review by the Texas Supreme Court, the Company anticipates that it would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue described below and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $130 million to $350 million plus interest subsequent to December 31, 2007.

In the True-Up Order the Texas Utility Commission reduced CenterPoint Houston's stranded cost recovery by approximately $146 million, which was included in the extraordinary loss discussed above, for the present value of certain deferred tax benefits associated with its former electric generation assets. The Company believes that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 which would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, in December 2005, the IRS withdrew those proposed normalization regulations and issued new proposed regulations that do not include the provision allowing a retroactive election to pass the tax benefits back to customers. The Company subsequently requested a Private Letter Ruling (PLR) asking the IRS whether the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations. In that ruling, which was received in August 2007, the IRS concluded that such reductions would cause normalization violations with respect to the ADITC and EDFIT. As in a similar PLR issued in May 2006 to another Texas utility, the IRS did not reference its proposed regulations.

The district court affirmed the Texas Utility Commission's ruling on the tax normalization issue, but in response to a request from the Texas Utility Commission, the court of appeals ordered that the tax normalization issue be remanded for further consideration. If the Texas Utility Commission's order relating to the ADITC reduction is not reversed or otherwise modified on remand so as to eliminate the normalization violation, the IRS could require the Company to pay an amount equal to CenterPoint Houston's unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. Such treatment if required by the IRS, could have a material adverse impact on the Company's results of operations, financial condition and cash flows in addition to any potential loss resulting from final resolution of the True-Up Order. However, the Company and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate or administrative process. Although the Texas Utility Commission has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation, no prediction can be made as to the ultimate action the Texas Utility Commission may take on this issue on remand.

The Texas electric restructuring law allowed the amounts awarded to CenterPoint Houston in the Texas Utility Commission's True-Up Order to be recovered either through the issuance of transition bonds or through implementation of a competition transition charge (CTC) or both. Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed by a Travis County district court, in December 2005 a subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84% to 5.30% and final maturity dates ranging from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

In July 2005, CenterPoint Houston received an order from the Texas Utility Commission allowing it to implement a CTC designed to collect the remaining $596 million from the True-Up Order over 14 years plus interest at an annual rate of 11.075% (CTC Order). The CTC Order authorized CenterPoint Houston to impose a charge on retail electric providers to recover the portion of the true-up balance not recovered through a financing order. The CTC Order also allowed CenterPoint Houston to collect approximately $24 million of rate case expenses over three years without a return through a separate tariff rider (Rider RCE). CenterPoint Houston implemented the CTC and Rider RCE effective September 13, 2005 and began recovering approximately $620 million. Effective September 13, 2005, the return on the CTC portion of the true-up balance is included in CenterPoint Houston's tariff-based revenues.

Certain parties appealed the CTC Order to a district court in Travis County. In May 2006, the district court issued a judgment reversing the CTC Order in three respects. First, the court ruled that the Texas Utility

Commission had improperly relied on provisions of its rule dealing with the interest rate applicable to CTC amounts. The district court reached that conclusion based on its belief that the Texas Supreme Court had previously invalidated that entire section of the rule. The 11.075% interest rate in question was applicable from the implementation of the CTC Order on September 13, 2005 until August 1, 2006, the effective date of the implementation of a new CTC in compliance with the new rule discussed below. Second, the district court reversed the Texas Utility Commission's ruling that allows CenterPoint Houston to recover through the Rider RCE the costs (approximately $5 million) for a panel appointed by the Texas Utility Commission in connection with the valuation of electric generation assets. Finally, the district court accepted the contention of one party that the CTC should not be allocated to retail customers that have switched to new on-site generation. The Texas Utility Commission and CenterPoint Houston disagree with the district court's conclusions and, in May 2006, appealed the judgment to the Texas Third Court of Appeals, and if required, CenterPoint Houston plans to seek further review from the Texas Supreme Court. All briefs in the appeal have been filed, and oral arguments were held in December 2006. The ultimate outcome of this matter cannot be predicted at this time. However, the Company does not expect the disposition of this matter to have a material adverse effect on the Company's or CenterPoint Houston's financial condition, results of operations or cash flows.

In June 2006, the Texas Utility Commission adopted the revised rule governing the carrying charges on unrecovered CTC balances as recommended by its staff (Staff). The rule, which applies to CenterPoint Houston, reduced the allowed interest rate on the unrecovered CTC balance prospectively from 11.075% to a weighted average cost of capital of 8.06%. The annualized impact on operating income is a reduction of approximately $18 million per year for the first year with lesser impacts in subsequent years. In July 2006, CenterPoint Houston made a compliance filing necessary to implement the rule changes effective August 1, 2006.

During the years ended December 31, 2005, 2006 and 2007, CenterPoint Houston recognized approximately $19 million, $55 million and $42 million, respectively, in operating income from the CTC. Additionally, during the years ended December 31, 2005, 2006 and 2007, CenterPoint Houston recognized approximately $1 million, $13 million and $14 million, respectively, of the allowed equity return not previously recorded. As of December 31, 2007, the Company had not recorded an allowed equity return of $220 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates.

During the 2007 legislative session, the Texas legislature amended statutes prescribing the types of true-up balances that can be securitized by utilities and authorized the issuance of transition bonds to recover the balance of the CTC. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of the remaining balance of the CTC, after taking into account the environmental refund and the fuel reconciliation settlement amounts discussed below. CenterPoint Houston reached substantial agreement with other parties to this proceeding, and a financing order was approved by the Texas Utility Commission in September 2007. In February 2008, a new special purpose subsidiary of CenterPoint Houston issued approximately $488 million of transition bonds pursuant to the financing order in two tranches with interest rates of 4.192% and 5.234% and final maturity dates of February 2020 and February 2023, respectively. Contemporaneously with the issuance of those bonds, the CTC was terminated and a transition charge was implemented.

(b) Final Fuel Reconciliation

The results of the Texas Utility Commission's final decision related to CenterPoint Houston's final fuel reconciliation were a component of the True-Up Order. CenterPoint Houston appealed certain portions of the True-Up Order involving a disallowance of approximately $67 million relating to the final fuel reconciliation in 2003 plus interest of $10 million. That decision was upheld by a Travis County district court and affirmed by the Texas Third Court of Appeals. Although it filed an appeal with the Texas Supreme Court, in February 2007 CenterPoint Houston asked the Texas Supreme Court to hold that appeal in abeyance pending consideration by the Texas Utility Commission of a tentative settlement reached by the parties. In October 2007 the Texas Utility

Commission issued a final order consistent with the settlement, and the Texas Supreme Court ultimately vacated the lower court decisions. The settlement allows CenterPoint Houston recovery of $12.5 million plus interest from January 2002. As a result of the settlement, CenterPoint Houston recorded a regulatory asset of $17 million in 2007.

(c) Refund of Environmental Retrofit Costs

The True-Up Order allowed recovery of approximately $699 million of environmental retrofit costs related to CenterPoint Houston's generation assets. The True-Up Order required CenterPoint Houston to provide evidence by January 31, 2007 that the entire $699 million was actually spent by December 31, 2006 on environmental programs and provided for the Texas Utility Commission to determine the appropriate manner to return to customers any unused portion of these funds, including interest on the funds and on stranded costs attributable to the environmental costs portion of the stranded costs recovery. In January 2007, the successor in interest to CenterPoint Houston's generation assets advised that, as of December 31, 2006, it had spent only approximately $664 million. On January 31, 2007, CenterPoint Houston made the required filing with the Texas Utility Commission, identifying approximately $35 million in unspent funds to be refunded to customers along with approximately $7 million of interest and requesting permission to refund these amounts through a reduction of the CTC. Such amounts were recorded as regulatory liabilities as of December 31, 2006. In July 2007, CenterPoint Houston, the Staff and the other parties filed a settlement agreement in which it was agreed that the total amount of the refund, including all principal and interest, was $45 million as of May 31, 2007, that interest would continue to accrue after May 31, 2007 on any unrefunded balance at a rate of 5.4519% per year and that the refund should be used to offset the principal amount proposed in CenterPoint Houston's application to securitize the CTC and other amounts. The offset occurred in connection with the $488 million of transition bonds issued in February 2008. In August 2007, the Texas Utility Commission issued a final order consistent with the terms of that settlement agreement. As of December 31, 2007, CenterPoint Houston had recorded a regulatory liability of $46 million related to this matter.

(d) Rate Cases

Natural Gas Distribution

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

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

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

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

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

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

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

(5) Derivative Instruments

The Company is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. The Company utilizes derivative instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices, weather and interest rates on its operating results and cash flows.

(a) Non-Trading Activities

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

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

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

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

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

Interest Rate Swaps. During 2002, the Company settled forward-starting interest rate swaps having an aggregate notional amount of $1.5 billion at a cost of $156 million, which was recorded in other comprehensive loss and was amortized into interest expense over the five-year life of the designated fixed-rate debt and was fully amortized at December 31, 2007. Amortization of amounts deferred in accumulated other comprehensive loss for 2005, 2006 and 2007 was $31 million, $31 million and $20 million, respectively.

Hedging of Future Debt Issuances. In each of December 2007 and January 2008, the Company entered into treasury rate lock derivative instruments having an aggregate notional value of $150 million to hedge the risk of changes in the benchmark interest rate prior to the forecasted issuance of $300 million of fixed-rate debt in 2008, as changes in the benchmark interest rate would cause variability in the Company’s forecasted interest payments. These treasury rate lock derivatives were designated as cash flow hedges. Accordingly, unrealized gains and losses associated with the treasury rate lock derivative instruments are recorded as a component of accumulated other comprehensive income. The realized gain or loss recognized upon settlement of the treasury rate lock agreement will be initially recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the life of the related financing arrangement. In 2007, the Company recognized a $2 million loss for these treasury rate locks in other comprehensive income. Ineffectiveness for the treasury rate locks was not material in 2007.

Embedded Derivative. The Company’s 3.75% convertible senior notes contain contingent interest provisions. The contingent interest component is an embedded derivative as defined by SFAS No. 133, and accordingly, must be split from the host instrument and recorded at fair value on the balance sheet. The value of the contingent interest component was not material at issuance or at December 31, 2007.

(b) Credit Risks

In addition to the risk associated with price movements, credit risk is also inherent in the Company's non-trading derivative activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. The following table shows the composition of the non-trading derivative assets of the Company as of December 31, 2006 and 2007 (in millions):

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

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

(6) Indexed Debt Securities (ZENS) and Time Warner Securities

(a) Original Investment in Time Warner Securities

In 1995, the Company sold a cable television subsidiary to TW and received TW convertible preferred stock (TW Preferred) as partial consideration. In July 1999, the Company converted its 11 million shares of TW Preferred into 45.8 million shares of TW Common. A subsidiary of the Company now holds 21.6 million shares of TW Common which are classified as trading securities under SFAS No. 115 and are expected to be held to facilitate the Company's ability to meet its obligation under the 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS). Unrealized gains and losses resulting from changes in the market value of the TW Common are recorded in the Company's Statements of Consolidated Income.

(b) ZENS

In September 1999, the Company issued its ZENS having an original principal amount of $1.0 billion. ZENS are exchangeable for cash equal to the market value of a specified number of shares of TW common. The Company pays interest on the ZENS at an annual rate of 2% plus the amount of any quarterly cash dividends paid in respect of the shares of TW Common attributable to the ZENS. The principal amount of ZENS is subject to being increased or decreased to the extent that the annual yield from interest and cash dividends on the reference shares of TW Common is less than or more than 2.309%. At December 31, 2007, ZENS having an original principal amount of $840 million and a contingent principal amount of $820 million were outstanding and were exchangeable, at the option of the holders, for cash equal to 95% of the market value of 21.6 million shares of TW Common deemed to be attributable to the ZENS. At December 31, 2007, the market value of such shares was approximately $357 million, which would provide an exchange amount of $404 for each $1,000 original principal amount of ZENS. At maturity, the holders of the ZENS will receive in cash the higher of the contingent principal amount of the ZENS or an amount based on the then-current market value of TW Common, or other securities distributed with respect to TW Common.

For accounting purposes, the ZENS obligation was bifurcated into a debt component and a derivative component (the holder's option to receive the appreciated value of TW Common at maturity). The debt component accretes through interest charges at 17.4% annually up to the contingent principal amount of the ZENS in 2029 which reflects exchanges and adjustments to maintain a 2.309% annual yield, as discussed above. The derivative component is recorded at fair value and changes in the fair value of the derivative component are recorded in the Company's Statements of Consolidated Income. During 2005, 2006 and 2007, the Company recorded a gain (loss) of $(44) million, $94 million and $(114) million, respectively, on the Company's investment in TW Common. During 2005, 2006 and 2007, the Company recorded a gain (loss) of $49 million, $(80) million and $111 million, respectively, associated with the fair value of the derivative component of the ZENS obligation. Changes in the fair value of the TW Common held by the Company are expected to substantially offset changes in the fair value of the derivative component of the ZENS.

The following table sets forth summarized financial information regarding the Company's investment in TW Common and the Company's ZENS obligation (in millions).

	TW Investment	Debt Component of ZENS	Derivative Component of ZENS
Balance at December 31, 2004	$ 421	$ 107	$ 341
Accretion of debt component of ZENS	—	2	—
Gain on indexed debt securities	—	—	(49)
Loss on TW Common	(44)	—	—
Balance at December 31, 2005	377	109	292
Accretion of debt component of ZENS	—	2	—
Loss on indexed debt securities	—	—	80
Gain on TW Common	94	—	—
Balance at December 31, 2006	471	111	372
Accretion of debt component of ZENS	—	3	—
Gain on indexed debt securities	—	—	(111)
Loss on TW Common	(114)	—	—
Balance at December 31, 2007	$ 357	$ 114	$ 261

(7) Equity

(a) Capital Stock

CenterPoint Energy has 1,020,000,000 authorized shares of capital stock, comprised of 1,000,000,000 shares of $0.01 par value common stock and 20,000,000 shares of $0.01 par value preferred stock.

(b) Shareholder Rights Plan

The Company has a Shareholder Rights Plan that states that each share of its common stock includes one associated preference stock purchase right (Right) which entitles the registered holder to purchase from the Company a unit consisting of one-thousandth of a share of Series A Preference Stock. The Rights, which expire on December 11, 2011, are exercisable upon some events involving the acquisition of 20% or more of the Company's outstanding common stock. Upon the occurrence of such an event, each Right entitles the holder to receive common stock with a current market price equal to two times the exercise price of the Right. At anytime prior to becoming exercisable, the Company may repurchase the Rights at a price of $0.005 per Right. There are 700,000 shares of Series A Preference Stock reserved for issuance upon exercise of the Rights.

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

	December 31, 2006 Long-Term	December 31, 2006 Current(1)	December 31, 2007 Long-Term	December 31, 2007 Current(1)
	(In millions)			
Short-term borrowings:				
CERC Corp. receivables facility	$ —	$ 187	$ —	$ 232
Long-term debt:				
CenterPoint Energy:				
ZENS(2)	$ —	$ 111	$ —	$ 114
Senior notes 5.875% to 7.25% due 2008 to 2017	600	—	650	200
Convertible senior notes 2.875% to 3.75% due 2023(3)	—	830	—	535
Pollution control bonds 5.60% to 6.70% due 2012 to 2027(4)	151	—	151	—
Pollution control bonds 4.70% to 8.00% due 2011 to 2030(5)	1,046	—	1,046	—
Bank loans due 2012(6)	—	—	131	—
Junior subordinated debentures payable to affiliate 8.257%(7)	—	103	—	—
CenterPoint Houston:				
First mortgage bonds 9.15% due 2021	102	—	102	—
General mortgage bonds 5.60% to 6.95% due 2013 to 2033	1,262	—	1,262	—
Pollution control bonds 3.625% to 5.60% due 2012 to 2027(8)	229	—	229	—
Transition Bonds 3.84% to 5.63% due 2006 to 2019	2,260	147	2,101	159
Bank loans due 2012(6)	—	—	50	—
CERC Corp.:				
Convertible subordinated debentures 6.00% due 2012	56	7	50	7
Senior notes 5.95% to 7.875% due 2007 to 2037	2,097	—	2,447	300
Bank loans due 2012(6)	—	—	150	—
Other	1	—	1	—
Unamortized discount and premium(9)	(2)	—	(6)	—
Total long-term debt	7,802	1,198	8,364	1,315
Total debt	$ 7,802	$ 1,385	$ 8,364	$ 1,547

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

(2) Upon adoption of SFAS No. 133 effective January 1, 2001, the Company's ZENS obligation was bifurcated into a debt component and an embedded derivative component. For additional information regarding ZENS, see Note 6(b). As ZENS are exchangeable for cash at any time at the option of the holders, these notes are classified as a current portion of long-term debt.

(3) All of the Company's 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007, as described in Note 8(b), "Long-term Debt — Convertible Debt."

(4) These series of debt are secured by first mortgage bonds of CenterPoint Houston.

(5) $527 million of these series of debt is secured by general mortgage bonds of CenterPoint Houston.

(6) Classified as long-term debt because the termination dates of the facilities under which the funds were borrowed are more than one year from the date noted.

(7) The junior subordinated debentures were issued to subsidiary trusts in connection with the issuance by those trusts of preferred securities. The trust preferred securities were deconsolidated effective December 31, 2003 pursuant to the adoption of FIN 46, "Consolidation of Variable Interest Entities — An Interpretation of ARB No. 51." All of the junior subordinated debentures issued to the Company's subsidiary trust were redeemed in February 2007.

(8) These series of debt are secured by general mortgage bonds of CenterPoint Houston.

(9) Debt acquired in business acquisitions is adjusted to fair market value as of the acquisition date. Included in long-term debt is additional unamortized premium related to fair value adjustments of long-term debt of $4 million and $3 million at December 31, 2006 and 2007, respectively, which is being amortized over the respective remaining term of the related long-term debt.

(a) Short-term Borrowings

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

(b) Long-term Debt

Senior Notes. In February 2007, the Company issued $250 million aggregate principal amount of senior notes due in February 2017 with an interest rate of 5.95%. The proceeds from the sale of the senior notes were used to repay debt incurred in satisfying the Company's $255 million cash payment obligation in connection with the conversion and redemption of its 2.875% Convertible Notes.

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

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

Revolving Credit Facilities. In June 2007, the Company, CenterPoint Houston and CERC Corp. entered into amended and restated bank credit facilities. The Company's amended credit facility is a $1.2 billion five-year senior unsecured revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on the Company's current credit ratings, versus the previous rate of LIBOR plus 60 basis points. The facility contains covenants, including a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization covenant.

The amended facility at CenterPoint Houston is a $300 million five-year senior unsecured revolving credit facility. The facility's first drawn cost remains at LIBOR plus 45 basis points based on CenterPoint Houston's current credit ratings. The facility contains covenants, including a debt (excluding transition bonds) to total capitalization covenant of 65%.

The amended facility at CERC Corp. is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility's first drawn cost remains at LIBOR plus 45 basis points based on CERC Corp.'s current credit ratings. The facility contains covenants, including a debt to total capitalization covenant of 65%.

Under each of the credit facilities, an additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on the borrower's credit rating.

As of December 31, 2007, the Company had $131 million of borrowings and approximately $28 million of outstanding letters of credit under its $1.2 billion credit facility, CenterPoint Houston had $50 million of borrowings and approximately $4 million of outstanding letters of credit under its $300 million credit facility and CERC Corp. had $150 million of borrowings and approximately $13 million of outstanding letters of credit under its $950 million credit facility. The Company and CERC Corp. had no commercial paper outstanding at December 31, 2007. The Company, CenterPoint Houston and CERC Corp. were in compliance with all debt covenants as of December 31, 2007.

Transition Bonds. Pursuant to a financing order issued by the Texas Utility Commission in September 2007, in February 2008 a subsidiary of CenterPoint Houston issued approximately $488 million in transition bonds in two tranches with interest rates of 4.192% and 5.234% and final maturity dates of February 2020 and February 2023, respectively. Scheduled final payment dates are February 2017 and February 2020. Through issuance of the transition bonds, CenterPoint Houston securitized transition property of approximately $483 million representing the remaining balance of the CTC less an environmental refund as reduced by the fuel reconciliation settlement amount. See Note 4(a) for further discussion.

Convertible Debt. On May 19, 2003, the Company issued $575 million aggregate principal amount of convertible senior notes due May 15, 2023 with an interest rate of 3.75%. As of December 31, 2007, holders could convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 89.4381 shares of common stock per $1,000 principal amount of notes at any time prior to maturity under the following circumstances: (1) if the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% or, following May 15, 2008, 110% of the conversion price per share of CenterPoint Energy common stock on such last trading day, (2) if the notes have been called for redemption, (3) during any period in which the credit ratings assigned to the notes by both Moody's Investors Service, Inc. (Moody's) and Standard & Poor's Ratings Services (S&P), a division of The McGraw-Hill Companies, are lower than Ba2 and BB, respectively, or the notes are no longer rated by at least one of these ratings services or their successors, or (4) upon the occurrence of specified corporate transactions, including the distribution to all holders of CenterPoint Energy common stock of certain rights entitling them to purchase shares of CenterPoint Energy common stock at less than the last reported sale price of a share of CenterPoint Energy common stock on the trading day prior to the declaration date of the distribution or the distribution to all holders of CenterPoint Energy common stock of the Company's assets, debt securities or certain rights to purchase the Company's securities, which distribution has a per share value exceeding 15% of the last reported sale price of a share of CenterPoint Energy common stock on the trading day immediately preceding the declaration date for such distribution. The notes originally had a conversion rate of 86.3558 shares of common stock per $1,000 principal amount of notes. However, the conversion rate has increased to 89.4381, in accordance with the terms of the notes, due to quarterly common stock dividends in excess of $0.10 per share.

Holders have the right to require the Company to purchase all or any portion of the notes for cash on May 15, 2008, May 15, 2013 and May 15, 2018 for a purchase price equal to 100% of the principal amount of the notes. The convertible senior notes also have a contingent interest feature requiring contingent interest to be paid to holders of notes commencing on or after May 15, 2008, in the event that the average trading price of a note for the applicable five-trading-day period equals or exceeds 120% of the principal amount of the note as of the day immediately preceding the first day of the applicable six-month interest period. For any six-month period, contingent interest will be equal to 0.25% of the average trading price of the note for the applicable five-trading-day period.

In August 2005, the Company accepted for exchange approximately $572 million aggregate principal amount of its 3.75% convertible senior notes due 2023 (Old Notes) for an equal amount of its new 3.75% convertible senior notes due 2023 (New Notes). As of December 31, 2007, New Notes of approximately $532 million remained outstanding and Old Notes of approximately $3 million remained outstanding. Under the terms of the New Notes, which are substantially similar to the Old Notes, settlement of the principal portion will be made in cash rather than stock.

In the fourth quarter of 2007, holders of the Company's 3.75% convertible senior notes converted approximately $40 million principal amount of such notes. Substantially all of such conversions were settled with a cash payment for the principal amount and delivery of 1.3 million shares of the Company's common stock for the excess value due converting holders.

In January and February 2008, holders of the Company's 3.75% convertible senior notes converted approximately $123 million principal amount of such notes. Substantially all of such conversions were settled with a cash payment for the principal amount and delivery of 4.1 million shares of the Company's common stock for the excess value due converting holders. A February 2008 conversion notice by a holder of $10 million principal amount of the Company's 3.75% convertible senior notes is expected to result in a March 2008 conversion and settlement with a cash payment for the principal amount and delivery of shares of the Company's common stock for the excess value due the converting holder.

As of December 31, 2006 and December 31, 2007, the 3.75% convertible senior notes are included as current portion of long-term debt in the Consolidated Balance Sheets because the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the quarter was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

In December 2006, the Company called its 2.875% Convertible Senior Notes due 2024 (2.875% Convertible Notes) for redemption on January 22, 2007 at 100% of their principal amount. The 2.875% Convertible Notes became immediately convertible at the option of the holders upon the call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% Convertible Notes were converted in January 2007. The $255 million principal amount of the 2.875% Convertible Notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of the Company's common stock.

Junior Subordinated Debentures (Trust Preferred Securities). In February 2007, the Company's 8.257% Junior Subordinated Deferrable Interest Debentures having an aggregate principal amount of $103 million were redeemed at 104.1285% of their principal amount and the related 8.257% capital securities issued by HL&P Capital Trust II were redeemed at 104.1285% of their aggregate liquidation value of $100 million.

Maturities. The Company's maturities of long-term debt, capital leases and sinking fund requirements, excluding the ZENS obligation and the 3.75% convertible senior notes, are $666 million in 2008, $181 million in 2009, $397 million in 2010, $782 million in 2011 and $636 million in 2012.

Liens. As of December 31, 2007, CenterPoint Houston's assets were subject to liens securing approximately $253 million of first mortgage bonds. Sinking or improvement fund and replacement fund requirements on the first mortgage bonds may be satisfied by certification of property additions. Sinking fund and replacement fund requirements for 2005, 2006 and 2007 have been satisfied by certification of property additions. The replacement fund requirement to be satisfied in 2008 is approximately $164 million, and the sinking fund requirement to be satisfied in 2008 is approximately $3 million. The Company expects CenterPoint Houston to meet these 2008 obligations by certification of property additions. As of December 31, 2007, CenterPoint Houston's assets were also subject to liens securing approximately $2.0 billion of general mortgage bonds which are junior to the liens of the first mortgage bonds.

(9) Income Taxes

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

	Year Ended December 31, 2005	2006 (In millions)	2007
Current:			
Federal	$ (74)	$ 373	$ 163
State	2	37	32
Total current	(72)	410	195
Deferred:			
Federal	208	(362)	47
State	17	14	(47)
Total deferred	225	(348)	—
Income tax expense	$ 153	$ 62	$ 195

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

	Year Ended December 31, 2005	2006 (In millions)	2007
Income from continuing operations before income taxes and extraordinary item	$ 378	$ 494	$ 594
Federal statutory rate	35%	35%	35%
Income taxes at statutory rate	132	173	208
Net addition (reduction) in taxes resulting from:			
State income taxes (benefit), net of valuation allowance and federal income tax	13	33	(10)
Amortization of investment tax credit	(8)	(7)	(8)
Tax basis balance sheet adjustments	—	—	25
Increase (decrease) in settled and uncertain income tax positions	32	(118)	(20)
Other, net	(16)	(19)	—
Total	21	(111)	(13)
Income tax expense	$ 153	$ 62	$ 195
Effective income tax rate	40.6%	12.6%	32.8%

In 2007, the Company recorded a $25 million deferred federal income tax expense as a result of its tax basis balance sheet analysis. The 2007 state income tax benefit of $10 million includes a benefit of approximately

$30 million, net of federal income tax effect, as a result of the revised Texas Franchise Tax Law (Texas Margin Tax) and a Texas state tax examination for the tax years 2002 through 2004.

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

	December 31, 2006	December 31, 2007
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 17	$ 17
Deferred gas costs	—	26
Total current deferred tax assets	17	43
Non-current:		
Loss and credit carryforwards	27	52
Deferred gas costs	60	—
Employee benefits	186	173
Other	56	6
Total non-current deferred tax assets before valuation allowance	329	231
Valuation allowance	(22)	(18)
Total non-current deferred tax assets	307	213
Total deferred tax assets, net	324	256
Deferred tax liabilities:		
Current:		
Unrealized gain on indexed debt securities	$ 194	$ 294
Unrealized gain on TW Common	109	77
Other	30	22
Total current deferred tax liabilities	333	393
Non-current:		
Depreciation	1,370	1,359
Regulatory assets, net	1,173	1,039
Other	87	50
Total non-current deferred tax liabilities	2,630	2,448
Total deferred tax liabilities	2,963	2,841
Accumulated deferred income taxes, net	$ 2,639	$ 2,585

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2007, the Company has approximately $181 million of state net operating loss carryforwards which expire in various years between 2008 and 2027. A valuation allowance has been established for approximately $79 million of the state net operating loss carryforwards that may not be realized. The Company has a state tax credit carryforward of approximately $45 million which expires in 2026.

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

Uncertain Income Tax Positions. The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the adoption of FIN 48, the Company recognized a decrease of approximately $2 million in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 accumulated deficit. A reconciliation of the change in unrecognized tax benefits from January 1, 2007 to December 31, 2007 is as follows (in millions):

Balance at January 1, 2007	$ 72
Tax positions related to prior years:	
Additions	28
Reductions	(20)
Tax positions related to current year:	
Additions	4
Settlements	(2)
Balance at December 31, 2007	$ 82

The Company has approximately $10 million of unrecognized tax benefits that, if recognized, would reduce the effective income tax rate. The Company recognizes interest and penalties as a component of income tax expense. In 2007, the Company recognized approximately $3 million of interest on uncertain income tax positions in the Statements of Consolidated Income and $4 million in the Consolidated Balance Sheets at January 1, 2007 and December 31, 2007. The Company does not expect the amount of unrecognized tax benefits to change significantly over the next 12 months.

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

In the fourth quarter of 2006, the Company reached a final settlement with the IRS on the ACES and ZENS issues and executed a closing agreement on the ZENS resulting in a net reduction in income tax expense in 2006 of approximately $92 million. The Company also reached a tentative settlement on other tax issues, including those related to prior acquisitions and dispositions, resulting in a reduction in income tax expense for 2006 of approximately $26 million.

(10) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to the Company's Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, which have various quantity requirements and durations, that are not classified as non-trading derivative assets and liabilities in the Company's Consolidated Balance Sheets as of December 31, 2006 and December 31, 2007 as these contracts meet the SFAS No. 133 exception to be classified as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas supply commitments also include natural gas transportation contracts that do not meet the definition of a derivative. As of December 31, 2007, minimum payment obligations for natural gas supply commitments are approximately $743 million in 2008, $285 million in 2009, $278 million in 2010, $280 million in 2011, $270 million in 2012 and $1.2 billion in 2013 and thereafter.

(b) Lease Commitments

The following table sets forth information concerning the Company's obligations under non-cancelable long-term operating leases at December 31, 2007, which primarily consist of rental agreements for building space, data processing equipment and vehicles (in millions):

2008	$ 19
2009	13
2010	9
2011	7
2012	6
2013 and beyond	14
Total	$ 68

Total lease expense for all operating leases was $37 million, $56 million and $48 million during 2005, 2006 and 2007, respectively.

(c) Capital Commitments

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

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

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

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

Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter was increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that will increase the jointly owned capacity up to 500 MMcf per day, subject to FERC approval.

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

(d) Legal, Environmental and Other Regulatory Matters

Legal Matters

RRI Indemnified Litigation

The Company, CenterPoint Houston or their predecessor, Reliant Energy, Incorporated (Reliant Energy), and certain of their former subsidiaries are named as defendants in several lawsuits described below. Under a master separation agreement between the Company and RRI, the Company and its subsidiaries are entitled to be indemnified by RRI for any losses, including attorneys' fees and other costs, arising out of the lawsuits described below under *"Electricity and Gas Market Manipulation Cases"* and *"Other Class Action Lawsuits."* Pursuant to the indemnification obligation, RRI is defending the Company and its subsidiaries to the extent named in these lawsuits. Although the ultimate outcome of these matters cannot be predicted at this time, the Company has not considered it necessary to establish reserves related to this litigation.

Electricity and Gas Market Manipulation Cases. A large number of lawsuits have been filed against numerous market participants and remain pending in federal court in Wisconsin, Missouri and Nevada and in state court in California and Nevada in connection with the operation of the electricity and natural gas markets in California and certain other states in 2000-2001, a time of power shortages and significant increases in prices. These lawsuits, many of which have been filed as class actions, are based on a number of legal theories, including violation of state and federal antitrust laws, laws against unfair and unlawful business practices, the federal Racketeer Influenced Corrupt Organization Act, false claims statutes and similar theories and breaches of contracts to supply power to governmental entities. Plaintiffs in these lawsuits, which include state officials and governmental entities as well as private litigants, are seeking a variety of forms of relief, including recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages and punitive damages, injunctive relief, restitution, interest due, disgorgement, civil penalties and fines, costs of suit and attorneys' fees. The Company's former subsidiary, RRI, was a participant in the California markets, owning generating plants in the state and participating in both electricity and natural gas trading in that state and in western power markets generally.

The Company and/or Reliant Energy have been named in approximately 35 of these lawsuits, which were instituted between 2001 and 2007 and are pending in California state court in San Diego County, in Nevada state court in Clark County, in federal district court in Nevada and before the Ninth Circuit Court of Appeals. However, the Company, CenterPoint Houston and Reliant Energy were not participants in the electricity or natural gas markets in California. The Company and Reliant Energy have been dismissed from certain of the lawsuits, either voluntarily by the plaintiffs or by order of the court, and the Company believes it is not a proper defendant in the remaining cases and will continue to seek dismissal from such remaining cases.

To date, several of the electricity complaints have been dismissed, and several of the dismissals have been affirmed by appellate courts. Others have been resolved by the settlement described in the following paragraph. Three of the gas complaints were dismissed based on defendants' claims of the filed rate doctrine, but the Ninth

Circuit Court of Appeals reversed two of those dismissals and remanded the cases back to the district court for further proceedings. In June 2005, a San Diego state court refused to dismiss other gas complaints on the same basis. In October 2006, RRI reached a tentative settlement of 11 class action natural gas cases pending in state court in California. The court approved this settlement in June 2007. In the remaining gas cases in state court in California, the Court of Appeals found that the Company was not a successor to the liabilities of a subsidiary of RRI and ordered the state court to dismiss the Company. The other gas cases remain in the early procedural stages.

In August 2005, RRI reached a settlement with the FERC enforcement staff, the states of California, Washington and Oregon, California's three largest investor-owned utilities, classes of consumers from California and other western states, and a number of California city and county government entities that resolves their claims against RRI related to the operation of the electricity markets in California and certain other western states in 2000-2001. The settlement also resolves the claims of the three states and the investor-owned utilities related to the 2000-2001 natural gas markets. The settlement has been approved by the FERC, by the California Public Utilities Commission and by the courts in which the electricity class action cases are pending. Two parties have appealed the courts' approval of the settlement to the California Court of Appeals. A party in the FERC proceedings filed a motion for rehearing of the FERC's order approving the settlement, which the FERC denied in May 2006. That party has filed for review of the FERC's orders in the Ninth Circuit Court of Appeals. The Company is not a party to the settlement, but may rely on the settlement as a defense to any claims brought against it related to the time when the Company was an affiliate of RRI. The terms of the settlement do not require payment by the Company.

Other Class Action Lawsuits. In May 2002, three class action lawsuits were filed in federal district court in Houston on behalf of participants in various employee benefits plans sponsored by the Company. Two of the lawsuits were dismissed without prejudice. In the remaining lawsuit, the Company and certain current and former members of its benefits committee are defendants. That lawsuit alleged that the defendants breached their fiduciary duties to various employee benefits plans, directly or indirectly sponsored by the Company, in violation of the Employee Retirement Income Security Act of 1974 by permitting the plans to purchase or hold securities issued by the Company when it was imprudent to do so, including after the prices for such securities became artificially inflated because of alleged securities fraud engaged in by the defendants. The complaint sought monetary damages for losses suffered on behalf of the plans and a putative class of plan participants whose accounts held CenterPoint Energy or RRI securities, as well as restitution. In January 2006, the federal district judge granted a motion for summary judgment filed by the Company and the individual defendants. The plaintiffs appealed the ruling to the Fifth Circuit Court of Appeals, which heard oral arguments from the parties in October 2007. The Company believes that this lawsuit is without merit and will continue to vigorously defend the case. However, the ultimate outcome of this matter cannot be predicted at this time.

Other Legal Matters

Natural Gas Measurement Lawsuits. CERC Corp. and certain of its subsidiaries are defendants in a lawsuit filed in 1997 under the Federal False Claims Act alleging mismeasurement of natural gas produced from federal and Indian lands. The suit seeks undisclosed damages, along with statutory penalties, interest, costs and fees. The complaint is part of a larger series of complaints filed against 77 natural gas pipelines and their subsidiaries and affiliates. An earlier single action making substantially similar allegations against the pipelines was dismissed by the federal district court for the District of Columbia on grounds of improper joinder and lack of jurisdiction. As a result, the various individual complaints were filed in numerous courts throughout the country. This case has been consolidated, together with the other similar False Claims Act cases, in the federal district court in Cheyenne, Wyoming. In October 2006, the judge considering this matter granted the defendants' motion to dismiss the suit on the ground that the court lacked subject matter jurisdiction over the claims asserted. The plaintiff has sought review of that dismissal from the Tenth Circuit Court of Appeals, where the matter remains pending.

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

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

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

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

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

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

Environmental Matters

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

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

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

Manufactured Gas Plant Sites. CERC and its predecessors operated manufactured gas plants (MGP) 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, 2007, 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 (PRP), 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. As of December 31, 2007, CERC had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by 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 the subject of the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. The Company is investigating details regarding the site and the range of environmental expenditures for potential remediation. However, 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.

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

Asbestos. Some facilities owned by the Company contain or have contained asbestos insulation and other asbestos-containing materials. The Company or its subsidiaries have been named, along with numerous others, as a defendant in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos. Some of the claimants have worked at locations owned by the Company, but most existing claims relate to facilities previously owned by the Company or its subsidiaries. The Company anticipates that additional claims like those received may be asserted in the future. In 2004, the Company sold its generating business, to which most of these claims relate, to Texas Genco LLC, which is now known as NRG Texas LP (NRG). Under the terms of the arrangements regarding separation of the generating business from the Company and its sale to Texas Genco LLC, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by Texas Genco LLC and its successor, but the Company has agreed to continue to defend such claims to the extent they are covered by insurance maintained by the Company, subject to reimbursement of the costs of such defense from the purchaser. Although their ultimate outcome cannot be predicted at this time, the Company intends to continue vigorously contesting claims that it does not consider to have merit and does not expect, based on its experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on the Company's financial condition, results of operations or cash flows.

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

Other Proceedings

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

In July 2007, the Company was notified of acceptance of its claim in connection with the 2002 AOL Time Warner, Inc. securities and ERISA class action litigation by receipt of approximately $32 million from the independent settlement administrator appointed by the United States District Court, Southern District of New York. Pursuant to the terms of the Indenture governing the Company's ZENS, in August 2007, the Company distributed to current ZENS holders approximately $27 million, which amount represented the portion of the payment received that was attributable to the reference shares of TW Common stock corresponding to each ZENS. This distribution reduced the contingent principal amount of the ZENS from $848 million to $821 million. The litigation settlement was recorded as other income and the distribution to ZENS holders was recorded as other expense during the third quarter of 2007.

Guaranties

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

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

(11) Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents, investments in debt and equity securities classified as "available-for-sale" and "trading" in accordance with SFAS No. 115, and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair values of non-trading derivative assets and liabilities are equivalent to their carrying amounts in the Consolidated Balance Sheets at December 31, 2006 and 2007 and have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques (see Note 5). Therefore, these financial instruments are stated at fair value and are excluded from the table below.

	December 31, 2006		December 31, 2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Financial liabilities:				
Long-term debt (excluding capital leases)	$ 8,889	$ 9,573	$ 9,564	$ 10,048

(12) Earnings Per Share

The following table reconciles numerators and denominators of the Company's basic and diluted earnings (loss) per share calculations:

	For the Year Ended December 31, 2005	2006	2007
	(In millions, except per share and share amounts)		
Basic earnings (loss) per share calculation:			
Income from continuing operations before extraordinary item	$ 225	$ 432	$ 399
Loss from discontinued operations, net of tax	(3)	—	—
Extraordinary item, net of tax	30	—	—
Net income	$ 252	$ 432	$ 399
Weighted average shares outstanding	309,349,000	311,826,000	320,480,000
Basic earnings (loss) per share:			
Income from continuing operations before extraordinary item	$ 0.72	$ 1.39	$ 1.25
Loss from discontinued operations, net of tax	(0.01)	—	—
Extraordinary item, net of tax	0.10	—	—
Net income	$ 0.81	$ 1.39	$ 1.25
Diluted earnings (loss) per share calculation:			
Net income	$ 252	$ 432	$ 399
Plus: Income impact of assumed conversions:			
Interest on 3.75% contingently convertible senior notes	9	—	—
Total earnings effect assuming dilution	$ 261	$ 432	$ 399
Weighted average shares outstanding	309,349,000	311,826,000	320,480,000
Plus: Incremental shares from assumed conversions:			
Stock options(1)	1,241,000	974,000	1,059,000
Restricted stock	1,851,000	1,553,000	1,928,000
2.875% convertible senior notes	—	1,625,000	291,000
3.75% convertible senior notes	33,587,000	8,800,000	18,749,000
Weighted average shares assuming dilution	346,028,000	324,778,000	342,507,000
Diluted earnings (loss) per share:			
Income from continuing operations before extraordinary item	$ 0.67	$ 1.33	$ 1.17
Loss from discontinued operations, net of tax	(0.01)	—	—
Extraordinary item, net of tax	0.09	—	—
Net income	$ 0.75	$ 1.33	$ 1.17

(1) Options to purchase 8,677,660, 5,863,907 and 3,225,969 shares were outstanding for the years ended December 31, 2005, 2006 and 2007, respectively, but were not included in the computation of diluted earnings

(loss) per share because the options' exercise price was greater than the average market price of the common shares for the respective years.

All of the 2.875% contingently convertible senior notes and substantially all of the 3.75% contingently convertible senior notes provide for settlement of the principal portion in cash rather than stock. In accordance with EITF Issue No. 04-8, "Accounting Issues related to Certain Features of Contingently Convertible Debt and the Effect on Diluted Earnings Per Share," the portion of the conversion value of such notes that must be settled in cash rather than stock is excluded from the computation of diluted earnings per share from continuing operations. The Company includes the conversion spread in the calculation of diluted earnings per share when the average market price of the Company's common stock in the respective reporting period exceeds the conversion price. The conversion price for the 3.75% contingently convertible senior notes at December 31, 2007 was $11.18 and the conversion price of the 2.875% convertible senior notes at the time of their extinguishment was $12.52. All of the Company's 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007, as described in Note 8(b), "Long-term Debt — Convertible Debt."

(13) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2006 (In millions, except per share amounts)			
	First Quarter	Second Quarter(1)	Third Quarter	Fourth Quarter
Revenues	$ 3,077	$ 1,843	$ 1,935	$ 2,464
Operating income	306	220	284	235
Net income	88	194	83	67
Basic earnings per share:(2)				
Net income	$ 0.28	$ 0.62	$ 0.27	$ 0.21
Diluted earnings per share:(2)				
Net income	$ 0.28	$ 0.61	$ 0.26	$ 0.20

	Year Ended December 31, 2007 (In millions, except per share amounts)			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 3,106	$ 2,033	$ 1,882	$ 2,602
Operating income	353	242	287	303
Net income	130	70	91	108
Basic earnings per share:(2)				
Net income	$ 0.41	$ 0.22	$ 0.29	$ 0.34
Diluted earnings per share:(2)				
Net income	$ 0.38	$ 0.20	$ 0.27	$ 0.32

(1) In the second quarter of 2006, the Company reached agreements on the terms of two settlements. An agreement with the IRS regarding the tax treatment of the ZENS and ACES resulted in a reduction of income tax expense of $119 million ($0.38 per diluted share). An agreement with the Texas Utility Commission settling all issues related to the remand of the Company's 2001 unbundled cost of service order reduced income by $21 million after-tax ($0.07 per diluted share).

(2) Quarterly earnings per common share are based on the weighted average number of shares outstanding during the quarter, and the sum of the quarters may not equal annual earnings per common share. The Company

includes the conversion spread related to its contingently convertible senior notes in the calculation of diluted earnings per share when the average market price of the Company's common stock in the respective reporting period exceeds the conversion price. All of the Company's 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007, as described in Note 8(b), "Long-term Debt — Convertible Debt."

(14) Reportable Business Segments

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

The Company's reportable business segments include the following: Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. The electric transmission and distribution function (CenterPoint Houston) is reported in the Electric Transmission & Distribution business segment. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers. Competitive Natural Gas Sales and Services represents the Company's non-rate regulated gas sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. The Interstate Pipelines includes the interstate natural gas pipeline operations. The Field Services business segment includes the natural gas gathering operations. Other Operations consists primarily of other corporate operations which support all of the Company's business operations. The Company's generation operations, which were previously reported in the Electric Generation business segment, are presented as discontinued operations within these consolidated financial statements.

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.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Revenues from External Customers	Intersegment Revenues	Depreciation and Amortization	Operating Income (Loss)	Extraordinary Item, net of tax	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2005:							
Electric Transmission & Distribution	$ 1,644(1)	$ —	$ 322	$ 487	$ (30)	$ 8,227	$ 281
Natural Gas Distribution	3,837	9	152	175	—	4,612	249
Competitive Natural Gas Sales and Services	3,884	245	2	60	—	1,849	12
Interstate Pipelines	255	131	36	165	—	2,400	118
Field Services	91	29	9	70	—	529	38
Other	11	8	20	(18)	—	2,202(2)	21
Discontinued Operations	—	—	—	—	—	—	9
Reconciling Eliminations	—	(422)	—	—	—	(2,703)	—
Consolidated	$ 9,722	$ —	$ 541	$ 939	$ (30)	$ 17,116	$ 728
As of and for the year ended December 31, 2006:							
Electric Transmission & Distribution	$ 1,781(1)	$ —	$ 379	$ 576	$ —	$ 8,463	$ 389
Natural Gas Distribution	3,582	11	152	124	—	4,463	187
Competitive Natural Gas Sales and Services	3,572	79	1	77	—	1,501	18
Interstate Pipelines	255	133	37	181	—	2,738	437
Field Services	119	31	10	89	—	608	65
Other	10	5	20	(2)	—	2,047(2)	25
Reconciling Eliminations	—	(259)	—	—	—	(2,187)	—
Consolidated	$ 9,319	$ —	$ 599	$ 1,045	$ —	$ 17,633	$ 1,121
As of and for the year ended December 31, 2007:							
Electric Transmission & Distribution	$ 1,837(1)	$ —	$ 398	$ 561	$ —	$ 8,358	$ 401
Natural Gas Distribution	3,749	10	155	218	—	4,332	191
Competitive Natural Gas Sales and Services	3,534	45	5	75	—	1,221	7
Interstate Pipelines	357	143	44	237	—	3,007	308
Field Services	136	39	11	99	—	669	74
Other	10	—	18	(5)	—	1,956(2)	30
Reconciling Eliminations	—	(237)	—	—	—	(1,671)	—
Consolidated	$ 9,623	$ —	$ 631	$ 1,185	$ —	$ 17,872	$ 1,011

(1) Sales to subsidiaries of RRI in 2005, 2006 and 2007 represented approximately $812 million, $737 million and $661 million, respectively, of CenterPoint Houston's transmission and distribution revenues.

(2) Included in total assets of Other Operations as of December 31, 2005, 2006 and 2007 are pension assets of $654 million, $109 million and $231 million, respectively. Also included in total assets of Other Operations as of December 31, 2006 and 2007, are pension related regulatory assets of $420 million and $319 million, respectively, resulting from the Company's adoption of SFAS No. 158.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended December 31,		
	2005	2006 (In millions)	2007
Revenues by Products and Services:			
Electric delivery sales	$ 1,644	$ 1,781	$ 1,837
Retail gas sales	4,871	4,546	4,941
Wholesale gas sales	2,410	2,331	2,196
Gas transport	684	550	532
Energy products and services	113	111	117
Total	$ 9,722	$ 9,319	$ 9,623

(15) Subsequent Events

On January 24, 2008, the Company’s board of directors declared a regular quarterly cash dividend of $0.1825 per share of common stock payable on March 10, 2008, to shareholders of record as of the close of business on February 15, 2008.

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, 2007 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

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

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

On December 13, 2007, the Company's Board of Directors, on recommendation from its Compensation Committee, approved new change in control agreements for the Company's named executive officers and certain other officers of the Company. The forms of these agreements are attached to this Annual Report on Form 10-K as Exhibits 10(nn) and 10(oo) and are incorporated by reference herein. The new change in control agreements are substantially similar to the change in control agreements that had been in effect. The changes in the new agreements are designed solely to bring the agreements into compliance with the requirements of Internal Revenue Code Section 409A and the regulations promulgated thereunder.

PART III

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

The information called for by Item 10, to the extent not set forth in "Executive Officers" in Item 1, is or will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2008 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 11. ***Executive Compensation***

The information called for by Item 11 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2008 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 12 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2008 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 13 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2008 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 14. ***Principal Accounting Fees and Services***

The information called for by Item 14 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2008 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

PART IV

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

(a)(1) Financial Statements.

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

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

III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 129, which index also includes the management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
CenterPoint Energy, Inc.
Houston, Texas

We have audited the consolidated financial statements of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company's adoption of new accounting standards for defined benefit pension and other postretirement plans in 2006 and conditional asset retirement obligations in 2005), and the Company's internal control over financial reporting as of December 31, 2007, and have issued our reports thereon dated February 28, 2008; such reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules of the Company listed in the index at Item 15 (a)(2). These consolidated financial statement schedules are 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 schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2008

CENTERPOINT ENERGY, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF CENTERPOINT ENERGY, INC. (PARENT COMPANY)

STATEMENTS OF INCOME

	For the Year Ended December 31,		
	2005	2006	2007
		(In millions)	
Equity Income of Subsidiaries	$ 425	$ 560	$ 515
Interest Income from Subsidiaries	15	18	22
Other Income	—	6	1
Loss on Disposal of Subsidiary	(14)	—	—
Gain (Loss) on Indexed Debt Securities	49	(80)	111
Operation and Maintenance Expenses	(29)	(19)	(17)
Taxes Other than Income	—	(2)	(4)
Interest Expense to Subsidiaries	(61)	(69)	(67)
Interest Expense	(204)	(196)	(219)
Distribution to ZENS Holders	—	—	(27)
Income Tax Benefit	41	214	84
Extraordinary Item, net of tax	30	—	—
Net Income	$ 252	$ 432	$ 399

See CenterPoint Energy, Inc. and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8

CENTERPOINT ENERGY, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF CENTERPOINT ENERGY, INC. (PARENT COMPANY)

BALANCE SHEETS

	December 31, 2006	December 31, 2007
	(In millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ —	$ —
Notes receivable — subsidiaries	391	216
Accounts receivable — subsidiaries	271	106
Other assets	2	2
Total current assets	664	324
Other Assets:		
Investment in subsidiaries	5,568	5,848
Notes receivable — subsidiaries	151	151
Other assets	573	578
Total other assets	6,292	6,577
Total Assets	$ 6,956	$ 6,901
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Notes payable — subsidiaries	$ 158	$ 1
Current portion of long-term debt	941	849
Indexed debt securities derivative	372	261
Accounts payable:		
Subsidiaries	312	558
Other	(8)	3
Taxes accrued	726	372
Interest accrued	26	28
Non-trading derivative liabilities	—	2
Other	21	18
Total current liabilities	2,548	2,092
Other Liabilities:		
Accumulated deferred tax liabilities	223	193
Benefit obligations	71	78
Notes payable — subsidiaries	750	750
Other	12	1
Total non-current liabilities	1,056	1,022
Long-Term Debt	1,796	1,977
Shareholders' Equity:		
Common stock	3	3
Additional paid-in capital	2,977	3,023
Accumulated deficit	(1,355)	(1,172)
Accumulated other comprehensive loss	(69)	(44)
Total shareholders' equity	1,556	1,810
Total Liabilities and Shareholders' Equity	$ 6,956	$ 6,901

See CenterPoint Energy, Inc. and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8

CENTERPOINT ENERGY, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF CENTERPOINT ENERGY, INC. (PARENT COMPANY)

STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
	2005	2006	2007
		(In millions)	
Operating Activities:			
Net income	$ 252	$ 432	$ 399
Loss on disposal of subsidiary	14	—	—
Extraordinary item, net of tax	(30)	—	—
Adjusted income	236	432	399
Non-cash items included in net income:			
Equity income of subsidiaries	(425)	(560)	(515)
Deferred income tax expense	106	(169)	52
Tax and interest reserves reductions related to ZENS and ACES settlement	—	(107)	—
Amortization of debt issuance costs	37	36	46
Loss (gain) on indexed debt securities	(49)	80	(111)
Changes in working capital:			
Accounts receivable/(payable) from subsidiaries, net	1	33	20
Accounts payable	(1)	(13)	11
Other current assets	(1)	(1)	—
Other current liabilities	(73)	117	(50)
Common stock dividends received from subsidiaries	508	227	240
Pension contribution	(75)	—	—
Other	77	18	2
Net cash provided by operating activities	341	93	94
Investing Activities:			
Proceeds from sale of Texas Genco	700	—	—
Investments in subsidiaries	(144)	—	—
Short-term notes receivable from subsidiaries	(335)	69	175
Long-term notes receivable from subsidiaries	154	21	—
Net cash provided by investing activities	375	90	175
Financing Activities:			
Long-term revolving credit facility, net	(236)	(3)	131
Proceeds from long-term debt	—	—	250
Payments on long-term debt	—	—	(295)
Debt issuance costs	(5)	(3)	(2)
Common stock dividends paid	(124)	(187)	(218)
Proceeds from issuance of common stock, net	17	27	22
Short-term notes payable to subsidiaries	(122)	153	(157)
Long-term notes payable to subsidiaries	(245)	(171)	—
Net cash used in financing activities	(715)	(184)	(269)
Net Increase (Decrease) in Cash and Cash Equivalents	1	(1)	—
Cash and Cash Equivalents at Beginning of Year	—	1	—
Cash and Cash Equivalents at End of Year	$ 1	$ —	$ —

See CenterPoint Energy, Inc. and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8

CENTERPOINT ENERGY, INC.

SCHEDULE I — NOTES TO CONDENSED FINANCIAL INFORMATION (PARENT COMPANY)

(1) The condensed parent company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of CenterPoint Energy, Inc. (CenterPoint Energy or the Company) appearing in the Annual Report on Form 10-K. Bank facilities at CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp., indirect wholly owned subsidiaries of the Company, limit debt, excluding transition bonds, as a percentage of their total capitalization to 65%. These covenants could restrict the ability of these subsidiaries to distribute dividends to the Company.

(2) In July 2004, the Company announced its agreement to sell Texas Genco to Texas Genco LLC. In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco's principal remaining asset was its ownership interest in the South Texas Project Electric Generating Station, a nuclear generating facility. The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to the Company of $700 million, was completed in April 2005. The Company recorded an after tax loss of $14 million in 2005 related to the sale of Texas Genco.

(3) In each of December 2007 and January 2008, the Company entered into treasury rate lock derivative instruments having an aggregate notional value of $150 million to hedge the risk of changes in the benchmark interest rate prior to the forecasted issuance of $300 million of fixed-rate debt in 2008, as changes in the benchmark interest rate would cause variability in the Company's forecasted interest payments. These treasury rate lock derivatives were designated as cash flow hedges. Accordingly, unrealized gains and losses associated with the treasury rate lock derivative instruments are recorded as a component of accumulated other comprehensive income. The realized gain or loss recognized upon settlement of the treasury rate lock agreement will be initially recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the life of the related financing arrangement. In 2007, the Company recognized a $2 million loss for these treasury rate locks in other comprehensive income. Ineffectiveness for the treasury rate locks was not material in 2007.

(4) In February 2007, the Company issued $250 million aggregate principal amount of senior notes due in February 2017 with an interest rate of 5.95%. The proceeds from the sale of the senior notes were used to repay debt incurred in satisfying the Company's $255 million cash payment obligation in connection with the conversion and redemption of its 2.875% Convertible Notes.

In June 2007, the Company amended its $1.2 billion five-year senior unsecured revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on the Company's current credit ratings, versus the previous rate of LIBOR plus 60 basis points. The facility contains covenants, including a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization covenant.

Under the credit facility, an additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on the borrower's credit rating.

As of December 31, 2007, the Company had $131 million of borrowings and approximately $28 million of outstanding letters of credit under its $1.2 billion credit facility. The Company had no commercial paper outstanding at December 31, 2007. The Company was in compliance with all covenants as of December 31, 2007.

On May 19, 2003, the Company issued $575 million aggregate principal amount of convertible senior notes due May 15, 2023 with an interest rate of 3.75%. As of December 31, 2007, holders could convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 89.4381 shares of common stock per $1,000 principal amount of notes at any time prior to maturity under the following circumstances: (1) if the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% or, following May 15, 2008, 110% of the conversion price per share of CenterPoint Energy common stock on such last trading day, (2) if the notes have been called for redemption, (3) during any period in which the credit ratings assigned to the notes by both Moody's Investors Service, Inc. (Moody's) and Standard & Poor's Ratings Services (S&P), a division of The McGraw-Hill Companies, are lower than Ba2 and BB, respectively, or the notes are no longer rated by at least one of these ratings services or their successors, or (4) upon the occurrence of specified corporate transactions, including the distribution to all holders of CenterPoint Energy common stock of certain rights entitling them to purchase shares of CenterPoint Energy common stock at less than the last reported sale price of a share of CenterPoint Energy common stock on the trading day prior to the declaration date of the distribution or the distribution to all holders of CenterPoint Energy common stock of the Company's assets, debt securities or certain rights to purchase the Company's securities, which distribution has a per share value exceeding 15% of the last reported sale price of a share of CenterPoint Energy common stock on the trading day immediately preceding the declaration date for such distribution. The notes originally had a conversion rate of 86.3558 shares of common stock per $1,000 principal amount of notes. However, the conversion rate has increased to 89.4381, in accordance with the terms of the notes, due to quarterly common stock dividends in excess of $0.10 per share.

Holders have the right to require the Company to purchase all or any portion of the notes for cash on May 15, 2008, May 15, 2013 and May 15, 2018 for a purchase price equal to 100% of the principal amount of the notes. The convertible senior notes also have a contingent interest feature requiring contingent interest to be paid to holders of notes commencing on or after May 15, 2008, in the event that the average trading price of a note for the applicable five-trading-day period equals or exceeds 120% of the principal amount of the note as of the day immediately preceding the first day of the applicable six-month interest period. For any six-month period, contingent interest will be equal to 0.25% of the average trading price of the note for the applicable five-trading-day period.

In August 2005, the Company accepted for exchange approximately $572 million aggregate principal amount of its 3.75% convertible senior notes due 2023 (Old Notes) for an equal amount of its new 3.75% convertible senior notes due 2023 (New Notes). As of December 31, 2007, New Notes of approximately $532 million remained outstanding and Old Notes of approximately $3 million remained outstanding. Under the terms of the New Notes, which are substantially similar to the Old Notes, settlement of the principal portion will be made in cash rather than stock.

In the fourth quarter of 2007, holders of the Company's 3.75% convertible senior notes converted approximately $40 million principal amount of such notes. Substantially all of such conversions were settled with a cash payment for the principal amount and delivery of 1.3 million shares of the Company's common stock for the excess value due converting holders.

In January and February 2008, holders of the Company's 3.75% convertible senior notes converted approximately $123 million principal amount of such notes. Substantially all of such conversions were settled with a cash payment for the principal amount and delivery of 4.1 million shares of the Company's common stock for the excess value due converting holders. A February 2008 conversion notice by a holder of $10 million principal amount of the Company's 3.75% convertible senior notes is expected to result in a March 2008 conversion and settlement with a cash payment for the principal amount and delivery of shares of the Company's common stock for the excess value due the converting holder.

As of December 31, 2006 and December 31, 2007, the 3.75% convertible senior notes are included as current portion of long-term debt in the Consolidated Balance Sheets because the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the quarter was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

In December 2006, the Company called its 2.875% Convertible Senior Notes due 2024 (2.875% Convertible Notes) for redemption on January 22, 2007 at 100% of their principal amount. The 2.875% Convertible Notes became immediately convertible at the option of the holders upon the call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% Convertible Notes were converted in January 2007. The $255 million principal amount of the 2.875% Convertible Notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of the Company's common stock.

Maturities. The Company's maturities of long-term debt, excluding the ZENS obligation and the 3.75% convertible senior notes, are $200 million in 2008, $-0- in 2009, $200 million in 2010, $19 million in 2011 and $131 million in 2012.

(5) CenterPoint Energy Services, Inc. (CES) provides comprehensive natural gas sales and services to industrial and commercial customers. In order to hedge their exposure to natural gas prices, CES has entered standard purchase and sale agreements with various counterparties. CenterPoint Energy has guaranteed the payment obligations of CES under certain of these agreements, typically for one-year terms. As of December 31, 2007, CenterPoint Energy had guaranteed $37 million under these agreements.

(6) In 2007, the Company transferred $389 million in deferred tax liabilities to a wholly owned subsidiary through intercompany accounts. These deferred tax liabilities relate to an investment in Time Warner Inc. common stock held by the subsidiary.

CENTERPOINT ENERGY, INC.

SCHEDULE II — QUALIFYING VALUATION ACCOUNTS
For the Three Years Ended December 31, 2007

Column A Description	Column B Balance at Beginning of Period	Column C Additions Charged to Income	Column D Deductions From Reserves(1)	Column E Balance at End of Period
		(In millions)		
Year Ended December 31, 2007:				
Accumulated provisions:				
Uncollectible accounts receivable	$ 33	$ 45	$ 40	$ 38
Deferred tax asset valuation allowance	22	(4)	—	18
Year Ended December 31, 2006:				
Accumulated provisions:				
Uncollectible accounts receivable	43	35	45	33
Deferred tax asset valuation allowance	21	1	—	22
Year Ended December 31, 2005:				
Accumulated provisions:				
Uncollectible accounts receivable	30	40	27	43
Deferred tax asset valuation allowance	20	1	—	21

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 28th day of February, 2008.

CENTERPOINT ENERGY, INC.
(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 February 28, 2008.

Signature	Title
/s/ DAVID M. MCCLANAHAN David M. McClanahan	President, Chief Executive Officer and Director (Principal Executive Officer and Director)
/s/ GARY L. WHITLOCK Gary L. Whitlock	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ WALTER L. FITZGERALD Walter L. Fitzgerald	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ MILTON CARROLL Milton Carroll	Chairman of the Board of Directors
/s/ DONALD R. CAMPBELL Donald R. Campbell	Director
/s/ DERRILL CODY Derrill Cody	Director
/s/ O. HOLCOMBE CROSSWELL O. Holcombe Crosswell	Director
/s/ JANIECE M. LONGORIA Janiece M. Longoria	Director
/s/ THOMAS F. MADISON Thomas F. Madison	Director
/s/ ROBERT T. O’CONNELL Robert T. O’Connell	Director

Signature	Title
/s/ MICHAEL E. SHANNON Michael E. Shannon	Director
/s/ PETER S. WAREING Peter S. Wareing	Director
/s/ SHERMAN M. WOLFF Sherman M. Wolff	Director

CENTERPOINT ENERGY, INC.

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

INDEX OF EXHIBITS

Exhibits included with this report are designated by a cross (†); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated by an asterisk (*) are management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K. CenterPoint Energy has not filed the exhibits and schedules to Exhibit 2. CenterPoint Energy hereby agrees to furnish supplementally a copy of any schedule omitted from Exhibit 2 to the SEC upon request.

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2	—	Transaction Agreement dated July 21, 2004 among CenterPoint Energy, Utility Holding, LLC, NN Houston Sub, Inc., Texas Genco Holdings, Inc. (“Texas Genco”), HPC Merger Sub, Inc. and GC Power Acquisition LLC	CenterPoint Energy’s Form 8-K dated July 21, 2004	1-31447	10.1
3(a)(1)	—	Amended and Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy’s Registration Statement on Form S-4	333-69502	3.1
3(a)(2)	—	Articles of Amendment to Amended and Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy’s Form 10-K for the year ended December 31, 2001	1-31447	3.1.1
3(b)	—	Amended and Restated Bylaws of CenterPoint Energy	CenterPoint Energy’s Form 8-K dated January 24, 2008	1-31447	3.1
3(c)	—	Statement of Resolution Establishing Series of Shares designated Series A Preferred Stock of CenterPoint Energy	CenterPoint Energy’s Form 10-K for the year ended December 31, 2001	1-31447	3.3
4(a)	—	Form of CenterPoint Energy Stock Certificate	CenterPoint Energy’s Registration Statement on Form S-4	333-69502	4.1
4(b)	—	Rights Agreement dated January 1, 2002, between CenterPoint Energy and JPMorgan Chase Bank, as Rights Agent	CenterPoint Energy’s Form 10-K for the year ended December 31, 2001	1-31447	4.2

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(c)	—	Contribution and Registration Agreement dated December 18, 2001 among Reliant Energy, CenterPoint Energy and the Northern Trust Company, trustee under the Reliant Energy, Incorporated Master Retirement Trust	CenterPoint Energy's Form 10-K for the year ended December 31, 2001	1-31447	4.3
4(d)(1)	—	Mortgage and Deed of Trust, dated November 1, 1944 between Houston Lighting and Power Company ("HL&P") and Chase Bank of Texas, National Association (formerly, South Texas Commercial National Bank of Houston), as Trustee, as amended and supplemented by 20 Supplemental Indentures thereto	HL&P's Form S-7 filed on August 25, 1977	2-59748	2(b)
4(d)(2)	—	Twenty-First through Fiftieth Supplemental Indentures to Exhibit 4(d)(1)	HL&P's Form 10-K for the year ended December 31, 1989	1-3187	4(a)(2)
4(d)(3)	—	Fifty-First Supplemental Indenture to Exhibit 4(d)(1) dated as of March 25, 1991	HL&P's Form 10-Q for the quarter ended June 30, 1991	1-3187	4(a)
4(d)(4)	—	Fifty-Second through Fifty-Fifth Supplemental Indentures to Exhibit 4(d)(1) each dated as of March 1, 1992	HL&P's Form 10-Q for the quarter ended March 31, 1992	1-3187	4
4(d)(5)	—	Fifty-Sixth and Fifty-Seventh Supplemental Indentures to Exhibit 4(d)(1) each dated as of October 1, 1992	HL&P's Form 10-Q for the quarter ended September 30, 1992	1-3187	4
4(d)(6)	—	Fifty-Eighth and Fifty-Ninth Supplemental Indentures to Exhibit 4(d)(1) each dated as of March 1, 1993	HL&P's Form 10-Q for the quarter ended March 31, 1993	1-3187	4
4(d)(7)	—	Sixtieth Supplemental Indenture to Exhibit 4(d)(1) dated as of July 1, 1993	HL&P's Form 10-Q for the quarter ended June 30, 1993	1-3187	4
4(d)(8)	—	Sixty-First through Sixty-Third Supplemental Indentures to Exhibit 4(d)(1) each dated as of December 1, 1993	HL&P's Form 10-K for the year ended December 31, 1993	1-3187	4(a)(8)
4(d)(9)	—	Sixty-Fourth and Sixty-Fifth Supplemental Indentures to Exhibit 4(d)(1) each dated as of July 1, 1995	HL&P's Form 10-K for the year ended December 31, 1995	1-3187	4(a)(9)

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(e)(1)	—	General Mortgage Indenture, dated as of October 10, 2002, between CenterPoint Energy Houston Electric, LLC and JPMorgan Chase Bank, as Trustee	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(1)
4(e)(2)	—	Second Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10- Q for the quarter ended September 30, 2002	1-3187	4(j)(3)
4(e)(3)	—	Third Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(4)
4(e)(4)	—	Fourth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10- Q for the quarter ended September 30, 2002	1-3187	4(j)(5)
4(e)(5)	—	Fifth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(6)
4(e)(6)	—	Sixth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(7)
4(e)(7)	—	Seventh Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(8)
4(e)(8)	—	Eighth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(9)
4(e)(9)	—	Officer's Certificates dated October 10, 2002 setting forth the form, terms and provisions of the First through Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	4(e)(10)
4(e)(10)	—	Ninth Supplemental Indenture to Exhibit 4(e)(1), dated as of November 12, 2002	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	4(e)(10)
4(e)(11)	—	Officer's Certificate dated November 12, 2003 setting forth the form, terms and provisions of the Ninth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	4(e)(12)
4(e)(12)	—	Tenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 18, 2003	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.1

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Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(e)(13)	—	Officer's Certificate dated March 18, 2003 setting forth the form, terms and provisions of the Tenth Series and Eleventh Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.2
4(e)(14)	—	Eleventh Supplemental Indenture to Exhibit 4(e)(1), dated as of May 23, 2003	CenterPoint Energy's Form 8-K dated May 16, 2003	1-31447	4.2
4(e)(15)	—	Officer's Certificate dated May 23, 2003 setting forth the form, terms and provisions of the Twelfth Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated May 16, 2003	1-31447	4.1
4(e)(16)	—	Twelfth Supplemental Indenture to Exhibit 4(e)(1), dated as of September 9, 2003	CenterPoint Energy's Form 8-K dated September 9, 2003	1-31447	4.2
4(e)(17)	—	Officer's Certificate dated September 9, 2003 setting forth the form, terms and provisions of the Thirteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated September 9, 2003	1-31447	4.3
4(e)(18)		Thirteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of February 6, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(16)
4(e)(19)		Officer's Certificate dated February 6, 2004 setting forth the form, terms and provisions of the Fourteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(17)
4(e)(20)		Fourteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of February 11, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(18)
4(e)(21)		Officer's Certificate dated February 11, 2004 setting forth the form, terms and provisions of the Fifteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(19)
4(e)(22)		Fifteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(20)

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(e)(23)		Officer's Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Sixteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(21)
4(e)(24)		Sixteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(22)
4(e)(25)		Officer's Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Seventeenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(23)
4(e)(26)		Seventeenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(24)
4(e)(27)		Officer's Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Eighteenth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(e)(25)
4(f)(1)	—	Indenture, dated as of February 1, 1998, between Reliant Energy Resources Corp. ("RERC Corp.") and Chase Bank of Texas, National Association, as Trustee	CERC Corp.'s Form 8-K dated February 5, 1998	1-13265	4.1
4(f)(2)	—	Supplemental Indenture No. 1 to Exhibit 4(f)(1), dated as of February 1, 1998, providing for the issuance of RERC Corp.'s $6^{1}/_{2}$% Debentures due February 1, 2008	CERC Corp.'s Form 8-K dated November 9, 1998	1-13265	4.2
4(f)(3)	—	Supplemental Indenture No. 2 to Exhibit 4(f)(1), dated as of November 1, 1998, providing for the issuance of RERC Corp.'s $6^{3}/_{8}$% Term Enhanced ReMarketable Securities	CERC Corp.'s Form 8-K dated November 9, 1998	1-13265	4.1
4(f)(4)	—	Supplemental Indenture No. 3 to Exhibit 4(f)(1), dated as of July 1, 2000, providing for the issuance of RERC Corp.'s 8.125% Notes due 2005	CERC Corp.'s Registration Statement on Form S-4	333-49162	4.2

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(f)(5)	—	Supplemental Indenture No. 4 to Exhibit 4(f)(1), dated as of February 15, 2001, providing for the issuance of RERC Corp.'s 7.75% Notes due 2011	CERC Corp.'s Form 8-K dated February 21, 2001	1-13265	4.1
4(f)(6)	—	Supplemental Indenture No. 5 to Exhibit 4(f)(1), dated as of March 25, 2003, providing for the issuance of CenterPoint Energy Resources Corp.'s ("CERC Corp.'s") 7.875% Senior Notes due 2013	CenterPoint Energy's Form 8-K dated March 18, 2003	1-31447	4.1
4(f)(7)	—	Supplemental Indenture No. 6 to Exhibit 4(f)(1), dated as of April 14, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	CenterPoint Energy's Form 8-K dated April 7, 2003	1-31447	4.2
4(f)(8)	—	Supplemental Indenture No. 7 to Exhibit 4(f)(1), dated as of November 3, 2003, providing for the issuance of CERC Corp.'s 5.95% Senior Notes due 2014	CenterPoint Energy's Form 8-K dated October 29, 2003	1-31447	4.2
4(f)(9)	—	Supplemental Indenture No. 8 to Exhibit 4(f)(1), dated as of December 28, 2005, providing for a modification of CERC Corp.'s $6^{1}/_{2}$% Debentures due 2008	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(f)(10)	—	Supplemental Indenture No. 9 to Exhibit 4(f)(1), dated as of May 18, 2006, providing for the issuance of CERC Corp.'s 6.15% Senior Notes due 2016	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2006	1-31447	4.7
4(f)(11)	—	Supplemental Indenture No. 10 to Exhibit 4(f)(1), dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CenterPoint Energy's Form 10-K for the year ended December 31, 2006	1-31447	4(f)(11)
4(f)(12)	—	Supplemental Indenture No. 11 to Exhibit 4(f)(1) dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.125% Senior Notes due 2017	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2007	1-31447	4.8

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Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(f)(13)	—	Supplemental Indenture No. 12 to Exhibit 4(f)(1) dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2007	1-31447	4.9
4(g)(1)	—	Indenture, dated as of May 19, 2003, between CenterPoint Energy and JPMorgan Chase Bank, as Trustee	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.1
4(g)(2)	—	Supplemental Indenture No. 1 to Exhibit 4(g)(1), dated as of May 19, 2003, providing for the issuance of CenterPoint Energy's 3.75% Convertible Senior Notes due 2023	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.2
4(g)(3)	—	Supplemental Indenture No. 2 to Exhibit 4(g)(1), dated as of May 27, 2003, providing for the issuance of CenterPoint Energy's 5.875% Senior Notes due 2008 and 6.85% Senior Notes due 2015	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.3
4(g)(4)	—	Supplemental Indenture No. 3 to Exhibit 4(g)(1), dated as of September 9, 2003, providing for the issuance of CenterPoint Energy's 7.25% Senior Notes due 2010	CenterPoint Energy's Form 8-K dated September 9, 2003	1-31447	4.2
4(g)(5)	—	Supplemental Indenture No. 4 to Exhibit 4(g)(1), dated as of December 17, 2003, providing for the issuance of CenterPoint Energy's 2.875% Convertible Senior Notes due 2024	CenterPoint Energy's Form 8-K dated December 10, 2003	1-31447	4.2

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(g)(6)	—	Supplemental Indenture No. 5 to Exhibit 4(g)(1), dated as of December 13, 2004, as supplemented by Exhibit 4(g)(5), relating to the issuance of CenterPoint Energy's 2.875% Convertible Senior Notes due 2024	CenterPoint Energy's Form 8-K dated December 9, 2004	1-31447	4.1
4(g)(7)	—	Supplemental Indenture No. 6 to Exhibit 4(g)(1), dated as of August 23, 2005, providing for the issuance of CenterPoint Energy's 3.75% Convertible Senior Notes, Series B due 2023	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(g)(7)
4(g)(8)	—	Supplemental Indenture No. 7 to Exhibit 4(g)(1), dated as of February 6, 2007, providing for the issuance of CenterPoint Energy's 5.95% Senior Notes due 2017	CenterPoint Energy's Form 10-K for the year ended December 31, 2006	1-31447	4(g)(8)
4(h)(1)	—	Subordinated Indenture dated as of September 1, 1999	Reliant Energy's Form 8-K dated September 1, 1999	1-3187	4.1
4(h)(2)	—	Supplemental Indenture No. 1 dated as of September 1, 1999, between Reliant Energy and Chase Bank of Texas (supplementing Exhibit 4(h)(1) and providing for the issuance Reliant Energy's 2% Zero-Premium Exchangeable Subordinated Notes Due 2029)	Reliant Energy's Form 8-K dated September 15, 1999	1-3187	4.2
4(h)(3)	—	Supplemental Indenture No. 2 dated as of August 31, 2002, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(h)(1))	CenterPoint Energy's Form 8-K12B dated August 31, 2002	1-31447	4(e)
4(h)(4)	—	Supplemental Indenture No. 3 dated as of December 28, 2005, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(h)(1))	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(h)(4)

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(i)	—	$1,200,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.3
4(j)	—	$300,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.4
4(k)	—	$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	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2007	1-31447	4.5

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, CenterPoint Energy has not filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities authorized does not exceed 10% of the total assets of CenterPoint Energy and its subsidiaries on a consolidated basis. CenterPoint Energy 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)	—	CenterPoint Energy Executive Benefits Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.4
*10(b)(1)	—	Executive Incentive Compensation Plan of Houston Industries Incorporated ("HI") effective as of January 1, 1982	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(b)
*10(b)(2)	—	First Amendment to Exhibit 10(b)(1) effective as of March 30, 1992	HI's Form 10-Q for the quarter ended March 31, 1992	1-7629	10(a)
*10(b)(3)	—	Second Amendment to Exhibit 10(b)(1) effective as of November 4, 1992	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(b)
*10(b)(4)	—	Third Amendment to Exhibit 10(b)(1) effective as of September 7, 1994	HI's Form 10-K for the year ended December 31, 1994	1-7629	10(b)(4)
*10(b)(5)	—	Fourth Amendment to Exhibit 10(b)(1) effective as of August 6, 1997	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(b)(5)
*10(c)(1)	—	Executive Incentive Compensation Plan of HI as amended and restated on January 1, 1991	HI's Form 10-K for the year ended December 31, 1990	1-7629	10(b)
*10(c)(2)	—	First Amendment to Exhibit 10(c)(1) effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(f)(2)
*10(c)(3)	—	Second Amendment to Exhibit 10(c)(1) effective as of March 30, 1992	HI's Form 10-Q for the quarter ended March 31, 1992	1-7629	10(d)
*10(c)(4)	—	Third Amendment to Exhibit 10(c)(1) effective as of November 4, 1992	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(f)(4)
*10(c)(5)	—	Fourth Amendment to Exhibit 10(c)(1) effective as of January 1, 1993	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(f)(5)
*10(c)(6)	—	Fifth Amendment to Exhibit 10(c)(1) effective in part, January 1, 1995, and in part, September 7, 1994	HI's Form 10-K for the year ended December 31, 1994	1-7629	10(f)(6)

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(c)(7)	—	Sixth Amendment to Exhibit 10(c)(1) effective as of August 1, 1995	HI's Form 10-Q for the quarter ended June 30, 1995	1-7629	10(a)
*10(c)(8)	—	Seventh Amendment to Exhibit 10(c)(1) effective as of January 1, 1996	HI's Form 10-Q for the quarter ended June 30, 1996	1-7629	10(a)
*10(c)(9)	—	Eighth Amendment to Exhibit 10(c)(1) effective as of January 1, 1997	HI's Form 10-Q for the quarter ended June 30, 1997	1-7629	10(a)
*10(c)(10)	—	Ninth Amendment to Exhibit 10(c)(1) effective in part, January 1, 1997, and in part, January 1, 1998	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(f)(10)
*10(d)	—	Benefit Restoration Plan of HI effective as of June 1, 1985	HI's Form 10-Q for the quarter ended March 31, 1987	1-7629	10(c)
*10(e)	—	Benefit Restoration Plan of HI as amended and restated effective as of January 1, 1988	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(g)(2)
*10(f)(1)	—	Benefit Restoration Plan of HI, as amended and restated effective as of July 1, 1991	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(g)(3)
*10(f)(2)	—	First Amendment to Exhibit 10(f)(1) effective in part, August 6, 1997, in part, September 3, 1997, and in part, October 1, 1997	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(i)(2)
†*10(g)	—	HI 1995 Section 415 Benefit Restoration Plan effective August 1, 1995			
*10(h)	—	CenterPoint Energy 1985 Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.1
*10(i)(1)	—	Reliant Energy 1994 Long- Term Incentive Compensation Plan, as amended and restated effective January 1, 2001	Reliant Energy's Form 10-Q for the quarter ended June 30, 2002	1-3187	10.6
*10(i)(2)	—	First Amendment to Exhibit 10(i)(1), effective December 1, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	10(p)(7)
*10(i)(3)	—	Form of Non-Qualified Stock Option Award Notice under Exhibit 10(i)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.6
*10(j)(1)	—	Savings Restoration Plan of HI effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1990	1-7629	10(f)
*10(j)(2)	—	First Amendment to Exhibit 10(j)(1) effective as of January 1, 1992	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(l)(2)
*10(j)(3)	—	Second Amendment to Exhibit 10(j)(1) effective in part, August 6, 1997, and in part, October 1, 1997	HI's Form 10-K for the year ended December 31, 1997	1-3187	10(q)(3)
*10(k)(1)	—	CenterPoint Energy Outside Director Benefits Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.6
*10(k)(2)	—	First Amendment to Exhibit 10(k)(1) effective as of January 1, 2004	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2004	1-31447	10.6
*10(l)	—	CenterPoint Energy Executive Life Insurance Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.5
*10(m)	—	Employment and Supplemental Benefits Agreement between HL&P and Hugh Rice Kelly	HI's Form 10-Q for the quarter ended March 31, 1987	1-7629	10(f)
10(n)(1)	—	Stockholder's Agreement dated as of July 6, 1995 between Houston Industries Incorporated and Time Warner Inc.	Schedule 13-D dated July 6, 1995	5-19351	2
10(n)(2)	—	Amendment to Exhibit 10(n)(1) dated November 18, 1996	HI's Form 10-K for the year ended December 31, 1996	1-7629	10(x)(4)

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(o)(1)	—	Houston Industries Incorporated Executive Deferred Compensation Trust effective as of December 19, 1995	HI's Form 10-K for the year ended December 31, 1995	1-7629	10(7)
*10(o)(2)	—	First Amendment to Exhibit 10(o)(1) effective as of August 6, 1997	HI's Form 10-Q for the quarter ended June 30, 1998	1-3187	10
*10(p)	—	Letter Agreement dated May 24, 2007 between CenterPoint Energy, Inc. and Milton Carroll, Non-Executive Chairman of the Board of Directors of CenterPoint Energy, Inc.	CenterPoint Energy's Form 8-K dated May 31, 2007	1-31447	10.1
*10(q)	—	Reliant Energy, Incorporated and Subsidiaries Common Stock Participation Plan for Designated New Employees and Non-Officer Employees, as amended and restated effective January 1, 2001	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(y)(2)
*10(r)(1)	—	Long-Term Incentive Plan of CenterPoint Energy, Inc. (amended and restated effective as of May 1, 2004)	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2004	1-31447	10.5
*10(r)(2)	—	First Amendment to Exhibit(r)(1), effective January 1, 2007	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2007	1-31447	10.5
*10(r)(3)	—	Form of Non-Qualified Stock Option Award Agreement under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.1
*10(r)(4)	—	Form of Restricted Stock Award Agreement under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.2
*10(r)(5)	—	Form of Performance Share Award under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated January 25, 2005	1-31447	10.3
*10(r)(6)	—	Form of Performance Share Award Agreement for 20XX-20XX Performance Cycle under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 22, 2006	1-31447	10.2
*10(r)(7)	—	Form of Restricted Stock Award Agreement (With Performance Vesting Requirement) under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 21, 2005	1-31447	10.2
*10(r)(8)	—	Form of Stock Award Agreement (With Performance Goal) under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 22, 2006	1-31447	10.3
*10(r)(9)	—	Form of Performance Share Award Agreement for 20XX — 20XX Performance Cycle under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 21, 2007	1-31447	10.1
*10(r)(10)	—	Form of Stock Award Agreement (With Performance Goal) under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 21, 2007	1-31447	10.2
*10(r)(11)	—	Form of Stock Award Agreement (Without Performance Goal) under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 21, 2007	1-31447	10.3
*10(r)(12)	—	Form of Performance Share Award Agreement for 20XX — 20XX Performance Cycle under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.1
*10(r)(13)	—	Form of Stock Award Agreement (With Performance Goal) under Exhibit 10(r)(1)	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.2
10(s)(1)	—	Master Separation Agreement entered into as of December 31, 2000 between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.1

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10(s)(2)	—	First Amendment to Exhibit 10(s)(1) effective as of February 1, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(bb)(5)
10(s)(3)	—	Employee Matters Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.5
10(s)(4)	—	Retail Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.6
10(s)(5)	—	Tax Allocation Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.8
10(t)(1)	—	Separation Agreement entered into as of August 31, 2002 between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(1)
10(t)(2)	—	Transition Services Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(2)
10(t)(3)	—	Tax Allocation Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(3)
*10(u)	—	Retention Agreement effective October 15, 2001 between Reliant Energy and David G. Tees	Reliant Energy's Form 10-K for the year ended December 31, 2001	1-3187	10(jj)
*10(v)	—	Retention Agreement effective October 15, 2001 between Reliant Energy and Michael A. Reed	Reliant Energy's Form 10-K for the year ended December 31, 2001	1-3187	10(kk)
*10(w)	—	Non-Qualified Unfunded Executive Supplemental Income Retirement Plan of Arkla, Inc. effective as of August 1, 1983	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(gg)
*10(x)(1)	—	Deferred Compensation Plan for Directors of Arkla, Inc. effective as of November 10, 1988	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(hh)(1)
*10(x)(2)	—	First Amendment to Exhibit 10(x)(1) effective as of August 6, 1997	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(hh)(2)
*10(y)(1)	—	CenterPoint Energy Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2003	1-31447	10.2
*10(y)(2)	—	First Amendment to Exhibit 10(y)(1) effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.4
*10(y)(3)	—	CenterPoint Energy 2005 Deferred Compensation Plan, effective January 1, 2008	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.3
*10(z)	—	CenterPoint Energy Short Term Incentive Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.3
*10(aa)	—	CenterPoint Energy Stock Plan for Outside Directors, as amended and restated effective May 7, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	10(ll)
10(bb)	—	City of Houston Franchise Ordinance	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2005	1-31447	10.1
10(cc)	—	Letter Agreement dated March 16, 2006 between CenterPoint Energy and John T. Cater	CenterPoint Energy's Form 10-Q for the quarter ended March 30, 2006	1-31447	10
†10(dd)	—	Summary of non-employee director compensation			

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
†10(ee)	—	Summary of named executive officer compensation			
†10(ff)	—	Form of Executive Officer Change in Control Agreement			
†10(gg)	—	Form of Corporate Officer Change in Control Agreement			
†12	—	Computation of Ratio of Earnings to Fixed Charges			
†21	—	Subsidiaries of CenterPoint Energy			
†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 10(g)

HOUSTON INDUSTRIES INCORPORATED
1995 SECTION 415 BENEFIT RESTORATION PLAN

(Established Effective August 1, 1995)

HOUSTON INDUSTRIES INCORPORATED
1995 SECTION 415 BENEFIT RESTORATION PLAN

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INDEX

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ARTICLE I

ESTABLISHMENT AND PURPOSE

1.1 Establishment: Houston Industries Incorporated, a Texas corporation (the "Company"), hereby establishes, effective August 1, 1995, an unfunded excess benefit plan within the meaning of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), for the benefit of certain eligible employees of the Company, Houston Lighting & Power Company and Houston Industries Energy, Inc. to be known as the Houston Industries Incorporated 1995 Section 415 Benefit Restoration Plan (the "Plan").

1.2 Purpose: The purpose of this Plan is generally to provide the amount of the benefit which would otherwise be paid from the Houston Industries Incorporated Retirement Plan (the "Retirement Plan") following implementation of the 1995 Voluntary Early Retirement Program adopted by the Board of Directors of the Company on May 3, 1995 (the "Program"), but which cannot be paid under the Retirement Plan due to the limitations on benefits and contributions imposed by Section 415 of the Internal Revenue Code of 1986, as amended (the "Code").

1.3 Application of Plan: The terms of this Plan are applicable only to those Persons who are Members hereunder.

1.4 ERISA Status: The Plan is intended to qualify for the exemptions provided under Title I of ERISA for plans that are excess benefit plans as defined in Section 3(36) of ERISA.

ARTICLE II

DEFINITIONS AND CONSTRUCTION

2.1 Definitions: Except as otherwise indicated, the terms used in this Plan shall have the same meaning as they have under the Retirement Plan. For purposes of this Plan, the following definitions shall apply:

(a) "Board of Directors" shall mean the Board of Directors of the Company.

(b) "Committee" shall mean the Benefits Committee appointed by the Board of Directors of the Company.

(c) "Company" shall mean Houston Industries Incorporated.

(d) “Member” shall mean a Person whose Houston Industries Incorporated Retirement Plan benefits, taking into consideration the benefit resulting from the Program’s implementation, are affected by the limitations imposed by Code Section 415.

(e) “Person” shall mean any person who fulfills the requirements for the Voluntary Early Pension for 1995 Program participants under Section 9.7(a) of the Houston Industries Incorporated Retirement Plan.

(f) “Program” shall mean the 1995 Voluntary Early Retirement Program adopted by the Board of Directors on May 3, 1995.

2.2 Gender and Number: Except when otherwise indicated by the context, any masculine terminology used in the Plan shall also include the feminine gender, and the definition of any term in the singular shall also include the plural.

2.3 Severability: In the event any provision of the Plan shall be held invalid or illegal for any reason, any illegality or invalidity shall not affect the remaining parts of the Plan, but the Plan shall be construed and enforced as if the illegal or invalid provision had never been inserted, and the Company shall have the privilege and opportunity to correct and remedy questions of illegality or invalidity by amendment as provided in the Plan.

2.4 Applicable Law: This Plan shall be governed and construed in accordance with ERISA and the laws of the State of Texas.

2.5 Plan Not an Employment Contract: The Plan is not an employment contract. The receipt of benefits under the Plan does not give to any person the right to be continued in employment by the Company or any of its subsidiaries, and all persons remain subject to change of salary, transfer, change of job, discipline, layoff, discharge (with or without cause), or any other change of employment status.

2.6 Funding: The benefits described in this Plan are contractual obligations of the Company to pay compensation for services, and shall constitute a liability to the Members and/or their beneficiaries in accordance with the terms hereof. All amounts paid under this Plan shall be paid in cash from the general assets of the Company. Benefits may be reflected on the accounting records of the Company but shall not be construed to create, or require the creation of, a trust, custodial or escrow account. No special or separate fund need be established and no segregation of assets need be made to assure the payment of such benefits. No Member shall have any right, title or interest whatever in or to any investment reserves, accounts, funds or assets that the Company may purchase, establish or accumulate to aid in providing the benefits described in this Plan. Nothing contained in this Plan, and no action taken pursuant to its provisions, shall create or be construed to create a trust or a fiduciary relationship of any kind between the Company and its subsidiaries and a Member or any other person. Neither a Member nor the beneficiary of a Member shall acquire any interest hereunder greater than that of an unsecured creditor.

2.7 Tax Withholding: The Company may withhold from a payment any federal, state or local taxes required by law to be withheld with respect to such payment.

2.8 Effect on Other Plans: Amounts accrued or paid under this Plan shall not be considered compensation for the purposes of the Company's qualified or welfare plans. Benefits payable hereunder shall not be duplicative of benefits paid under any other similar plan maintained by the Company to provide Retirement Plan restoration benefits to employees of the Company or its subsidiaries. In the event duplicate coverage arises, the Committee shall decide, in its sole discretion, which non-qualified plan shall provide the restoration benefit, and its decision shall be binding and conclusive.

ARTICLE III

RESTORATION OF BENEFITS REDUCED BY CODE SECTION 415

3.1 Purpose: Code Section 415 limits the amounts of benefits available under qualified retirement benefit plans. The purpose of this Plan is to restore to Members any benefits under the Retirement Plan that have been reduced as a result of the limitations imposed by Code Section 415.

3.2 Eligibility: A Member shall be eligible to receive benefits under this Plan as of August 1, 1995 (or such later employment termination date as is elected by the Member at the request of his Employer based on a specific business need).

3.3 Calculation of Restoration Benefit: When a Member's retirement benefit commences or a death benefit payable with respect to a Member commences under the Retirement Plan, the Company will calculate a benefit equal to the excess of the amount of the retirement benefit or death benefit (as the case may be) which would have been payable under the Retirement Plan, taking into consideration implementation of the Program, but for the limitations imposed by Code Section 415, over the amount of the retirement benefit or death benefit actually payable under the Retirement Plan. The Company shall generally pay a restoration benefit to the Member or to such other persons, at such times and in such manner as the Retirement Plan benefit is payable pursuant to the terms of the Retirement Plan. The Company shall convert the payment of a restoration benefit, the present value of which does not exceed $10,000, into an actuarially equivalent lump-sum payment; provided, however, in the sole discretion of the Committee, a Member may petition for payment at the same time and manner as the Retirement Plan benefit is payable if the present value of such lump-sum is in excess of $3,500. Conversion to a lump-sum shall be made in the manner determined by the Committee with the advice of the actuary for the Retirement Plan, employing those actuarial assumptions as are currently employed in converting Retirement Plan benefits from one form to another, and interest at the Pension Benefit Guaranty Corporation's rate in effect at the beginning of the Plan Year of the distribution.

3.4 Form of Payment and Commencement Date:

(a) Form of Payment: Except as otherwise provided above, benefits payable under this Plan shall be paid in the same manner as benefits payable under the Retirement Plan.

(b) Commencement Date: Benefits payable under this Plan shall commence on or about the same date that benefits commence under the Retirement Plan.

3.5 Vesting: A Member shall become vested in the benefit payable under this Plan at the same time that he becomes vested under the Retirement Plan. Notwithstanding the foregoing, a Member (and his beneficiary) shall have no right to a benefit under this Plan if the Committee determines that the Member engaged in a willful, deliberate or grossly negligent act or omission injurious to the finances or reputation of the Company or any of its subsidiaries.

ARTICLE IV

ADMINISTRATION

4.1 Administration: The Plan shall be administered, construed and interpreted by the Committee. The determinations of the Committee as to any disputed questions arising under the Plan, including the Persons who are eligible to be Members in the Plan and the amounts of their benefits under the Plan, and the construction and interpretation by the Committee of any provision of the Plan, shall be final, conclusive and binding upon all persons including Members, their beneficiaries, the Company, its subsidiaries, stockholders and employees.

4.2 Expenses: The expenses of administering the Plan shall be borne by the Company.

4.3 Indemnification and Exculpation: The members of the Committee and its agents shall be indemnified and held harmless by the Company against and from any and all loss, cost, liability or expenses that may be imposed upon or reasonably incurred by them in connection with or resulting from any claim, action, suit or proceeding to which they may be a party or in which they may be involved by reason of any action taken or failure to act under this Plan and against and from any and all amounts paid by them in settlement (with the Company's written approval) or paid by them in satisfaction of a judgment in any such action, suit or proceeding. The foregoing provisions shall not be applicable to any person if the loss, cost, liability or expense is due to such person's gross negligence or willful misconduct.

4.4 Non-Alienation of Benefits: Any benefit payable under this Plan shall not be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge, encumbrance or charge, and any attempt at such shall be void, and any such benefit shall not in any way be subject to the debts, contract, liabilities, engagements or torts of the person who shall be entitled to such benefit, nor shall it be subject to attachment or legal process for or against such person.

ARTICLE V

MERGER, AMENDMENT AND TERMINATION

5.1 Merger, Consolidation or Acquisition: In the event of a merger, consolidation or acquisition where the Company is not the surviving corporation, unless the successor or acquiring corporation shall elect to continue and carry on the Plan, this Plan shall terminate, and no additional benefits shall accrue for the Members. Unpaid benefits shall continue to be paid as scheduled unless the successor or acquiring corporation elects to accelerate payment.

5.2 Amendment and Termination: The Benefits Committee of the Board of Directors of the Company may amend, modify, or terminate the Plan in whole or in part at any time. In the event of a termination of the Plan pursuant to this Section, unpaid benefits accrued at the date of Plan termination shall continue to be an obligation of the Company and shall be paid as scheduled. No amendment or termination shall divest a Member of any benefit which had previously accrued to him or which had previously become payable to him under this Plan unless the Member agrees in writing to such divestment.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officers in a number of copies, each of which shall be deemed an original but all of which shall constitute one and the same instrument, this 18th day of May, 1995, but effective as of the date stated herein.

HOUSTON INDUSTRIES INCORPORATED

By /s/ D. D. Sykora
D. D. Sykora
President and Chief Operating Officer

ATTEST:

/s/ Richard Dauphin
Assistant Corporate Secretary

Exhibit 10(dd)

CenterPoint Energy, Inc.
Summary of Non-Employee Director Compensation

The following is a summary of compensation paid to the non-employee directors of CenterPoint Energy, Inc. (the "Company") effective May 24, 2007. For additional information regarding the compensation of the non-employee directors, please read the definitive proxy statement relating to the Company's 2008 annual meeting of shareholders to be filed pursuant to Regulation 14A.

- Annual retainer fee of $50,000 for Board membership;
- Fee of $2,000 for each Board or Committee meeting attended;
- Supplemental annual retainer of $10,000 for serving as a chairman of the Audit Committee; and
- Supplemental annual retainer of $5,000 for serving as a chairman of any other Board committee.

The Chairman receives the compensation payable to other non-employee directors plus supplemental compensation pursuant to a letter agreement with the Company incorporated by reference to Exhibit 10(p) to the Company's Annual Report on Form 10-K for the year ended December 31, 2007.

Stock Grants. Each non-employee director may also receive an annual grant of up to 5,000 shares of CenterPoint Energy common stock which vest in one-third increments on the first, second and third anniversaries of the grant date. Upon the initial nomination to the Board, in addition to the annual grant, a non-employee director may be granted a one-time grant of up to 5,000 shares of CenterPoint Energy common stock.

Deferred Compensation Plan. Directors may elect each year to defer all or part of their annual retainer fees and meeting fees. Directors participating in these plans may elect to receive distributions of their deferred compensation and interest in three ways: (i) an early distribution of either 50% or 100% of their account balance in any year that is at least four years from the year of deferral up to the year in which they reach age 70, (ii) a lump sum distribution payable in the year after they reach age 70 or upon leaving the Board of Directors, whichever is later, or (iii) 15 annual installments beginning on the first of the month coincident with or next following age 70 or upon leaving the Board of Directors, whichever is later.

Director Benefits Plan. Non-employee directors elected to the Board before 2004 participate in a director benefits plan under which a director who serves at least one full year will receive an annual cash amount equal to the annual retainer (excluding any supplemental retainer) in effect when the director terminates service. Payments under this plan begin the January following the later of the director's termination of service or attainment of age 65, and may be spread over a period of time to be selected by each director.

Executive Life Insurance Plan. Non-employee directors who were elected to the Board before 2001 participate in CenterPoint Energy's executive life insurance plan. This plan provides endorsement split-dollar life insurance with a death benefit of $180,000 with coverage continuing after the director's termination of service at age 65 or later. Directors elected to the Board after 2000 may not participate in this plan.

Exhibit 10(ee)

CenterPoint Energy, Inc.
Summary of Named Executive Officer Compensation

The following is a summary of compensation paid to the named executive officers of CenterPoint Energy, Inc. (the "Company"). For additional information regarding the compensation of the named executive officers, please read the definitive proxy statement relating to the Company's 2008 annual meeting of shareholders to be filed pursuant to Regulation 14A.

Base Salary. The following table sets forth the annual base salary of the Company's named executive officers effective April 1, 2008:

Name and Position	Base Salary
David M. McClanahan President and Chief Executive Officer	$ 1,060,000
Gary L. Whitlock Executive Vice President and Chief Financial Officer	$ 505,000
Scott E. Rozzell Executive Vice President, General Counsel and Corporate Secretary	$ 475,000
Thomas R. Standish Senior Vice President and Group President — Regulated Operations	$ 457,000
Byron R. Kelley Senior Vice President and Group President, Pipelines and Field Services	$ 390,000

Short Term Incentive Plan. Annual bonuses are paid to the Company's named executive officers pursuant to the Company's short term incentive plan, which provides for cash bonuses based on the achievement of certain performance objectives approved in accordance with the terms of the plan at the commencement of the year. Information regarding awards to the Company's named executive officers under the short term incentive plan is provided in definitive proxy statements relating to the Company's annual meeting of shareholders.

Long Term Incentive Plan. Under the Company's long term incentive plan, the Company's named executive officers may receive grants of (i) stock option awards, (ii) performance share awards, (iii) performance unit awards and/or (iv) stock awards. The current forms of the applicable award agreements pursuant to the Company's long term incentive plan are included as exhibits hereto.

CHANGE IN CONTROL AGREEMENT

THIS CHANGE IN CONTROL AGREEMENT (“Agreement”) is made as of this ___ day of December 2007, by and between CENTERPOINT ENERGY, INC., a Texas corporation (the “Company”), and **[NAME]** (“Executive”).

1. **Definitions:**

All terms defined in this Section 1 shall, throughout this Agreement, have the meanings given herein:

“Affiliate” means any company controlled by, controlling or under common control with the Company within the meaning of Section 414 of the Code.

“Board” means the board of directors of the Company.

“Cause” means Executive’s (a) gross negligence in the performance of Executive’s duties, (b) intentional and continued failure to perform Executive’s duties, (c) intentional engagement in conduct which is materially injurious to the Company or its Affiliates (monetarily or otherwise) or (d) conviction of a felony or a misdemeanor involving moral turpitude. For this purpose, an act or failure to act on the part of Executive will be deemed “intentional” only if done or omitted to be done by Executive not in good faith and without reasonable belief that his action or omission was in the best interest of the Company, and no act or failure to act on the part of Executive will be deemed “intentional” if it was due primarily to an error in judgment or negligence.

A **“Change in Control”** shall be deemed to have occurred upon the occurrence of any of the following events:

(a) ***30% Ownership Change***: Any Person makes an acquisition of Beneficial Ownership of Outstanding Voting Stock (including any acquisition of Beneficial Ownership deemed to have occurred pursuant to Rule 13d-5 under the Exchange Act) and is, immediately thereafter, the Beneficial Owner of 30% or more of the then Outstanding Voting Stock, unless such acquisition is made by a Parent Corporation resulting from a Business Combination (other than the Company) if, following such Business Combination, the conditions specified in clauses (i), (ii), (iii) and (iv) of subsection (c) of this definition are satisfied; or any Group is formed that is the Beneficial Owner of 30% or more of the Outstanding Voting Stock; or

(b) ***Board Majority Change***: Individuals who are Incumbent Directors cease for any reason to constitute a majority of the members of the Board; or

(c) ***Major Mergers and Acquisitions***: Approval by the shareholders of the Company of a Business Combination (or if there is no such approval by shareholders, consummation of such Business Combination) unless, immediately following such Business Combination, (i) all or substantially all of the individuals and entities that were the Beneficial Owners of the Outstanding Voting Stock immediately prior to such Business Combination will (or do) beneficially own, directly or indirectly, more than 70% of the then outstanding shares of voting stock of the Parent Corporation resulting from such Business Combination in substantially the same relative proportions as their ownership, immediately prior to such Business Combination, of the Outstanding Voting Stock, (ii) if the Business Combination involves the issuance or payment by the Company of consideration to another entity or its shareholders, the total fair market value of such consideration plus the principal amount of the consolidated long-term debt of the entity or business being acquired (in each case, determined as of the date of consummation of such Business Combination by a majority of the Incumbent Directors) will not (or does not) exceed 50% of the sum of the fair market value of the Outstanding Voting Stock plus the principal amount of the Company's consolidated long-term debt (in each case, determined immediately prior to such consummation by a majority of the Incumbent Directors), (iii) no Person (other than any Parent Corporation resulting from a Business Combination) will (or does) beneficially own, directly or indirectly, 30% or more of the then outstanding shares of voting stock of the Parent Corporation resulting from such Business Combination and (iv) a majority of the members of the board of directors of the Parent Corporation resulting from such Business Combination were Incumbent Directors immediately prior to consummation of such Business Combination; or

(d) ***Major Asset Dispositions***: Approval by the shareholders of the Company of a Major Asset Disposition (or if there is no such approval by shareholders consummation of such Major Asset Disposition) unless, immediately following such Major Asset Disposition, (i) individuals and entities that were Beneficial Owners of the Outstanding Voting Stock immediately prior to such Major Asset Disposition will (or do) beneficially own, directly or indirectly, more than 70% of the then outstanding shares of voting stock of the Company (if it continues to exist) and of the entity that acquires the largest portion of such assets (or the entity, if any, that owns a majority of the outstanding voting stock of such acquiring entity) and (ii) a majority of the members of the board of directors of the Company (if it continues to exist) and of the entity that acquires the largest portion of such assets (or the entity, if any, that owns a majority of the outstanding voting stock of such acquiring entity) were Incumbent Directors immediately prior to consummation of such Major Asset Disposition.

For purposes of the foregoing, the term:

(1) "Beneficial Owner," "Beneficial Ownership" and "Beneficially Own" are used as defined for purposes of Section 13(d)(3) under the Exchange Act.

(2) "Business Combination" means (x) a merger or consolidation involving the Company or its stock or (y) an acquisition by the Company, directly or through one or more subsidiaries, of another entity or its stock or assets.

(3) "Election Contest" is used as it is defined for purposes of Rule 14a-11 under the Exchange Act.

(4) "Exchange Act" means the Securities Exchange Act of 1934, as amended.

(5) "Group" is used as it is defined for purposes of Section 13(d)(3) of the Exchange Act.

(6) "Incumbent Director" means a director of the Company (x) who was a director of the Company on the date of this Agreement, or (y) who becomes a director subsequent to such date and whose election, or nomination for election by the Company's shareholders, was approved by a vote of a majority of the Incumbent Directors at the time of such election or nomination, except that any such director shall not be deemed an Incumbent Director if his initial assumption of office occurs as a result of an actual or threatened Election Contest or other actual or threatened solicitation of proxies by or on behalf of a Person other than the Board.

(7) "Major Asset Disposition" means the sale or other disposition in one transaction or a series of related transactions of 70% or more of the assets of the Company and its subsidiaries on a consolidated basis; and any specified percentage or portion of the assets of the Company shall be based on fair market value, as determined by a majority of the Incumbent Directors.

(8) "Outstanding Voting Stock" means outstanding voting securities of the Company entitled to vote generally in the election of directors; and any specified percentage or portion of the Outstanding Voting Stock (or of other voting stock) shall be determined based on the combined voting power of such securities.

(9) "Parent Corporation resulting from a Business Combination" means the Company if its stock is not acquired or converted in the Business Combination and otherwise means the entity which as a result of such Business Combination owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries.

(10) "Person" means an individual, entity or Group.

"Code" means the Internal Revenue Code of 1986, as amended.

"Common Stock" means the common stock, $0.01 par value, of the Company.

“Company” means CenterPoint Energy, Inc., a Texas corporation, and any successor thereto.

“Compensation” means the greater of (a) the sum of Executive’s annual base salary plus Target Bonus determined immediately prior to the date on which a Change in Control occurs, or (b) the sum of Executive’s annual base salary plus Target Bonus determined immediately prior to the date of his Covered Termination.

“Covered Termination” means any termination of Executive’s employment with the Company or any Affiliate that is a “Separation from Service” within the meaning of Code Section 409A and Treasury Regulation § 1.409A-1(h)(3) (or any successor regulations or guidance thereto) thereof:

(a) that does not result from any of the following:

(i) death;

(ii) disability entitling Executive to benefits under the Company’s long-term disability plan;

(iii) termination on or after age 65;

(iv) involuntary termination for Cause; or

(v) resignation by Executive, unless such resignation is for Good Reason; and

(b) that occurs:

(i) after the execution of a binding agreement to effect a Change in Control, subject to the Change in Control occurring; or

(ii) within two years after the date upon which a Change in Control occurs.

“Good Reason” means any one or more of the following:

(a) a failure to maintain Executive in the position, or a substantially equivalent position, with the Company and/or an Affiliate, as the case may be, which Executive held immediately prior to the Change in Control;

(b) a significant adverse change in the authorities, powers, functions, responsibilities or duties which Executive held immediately prior to the Change in Control;

(c) a reduction in Executive’s annual base salary as in effect immediately prior to the date on which a Change in Control occurs;

(d) a significant reduction in Executive's qualified retirement benefits, nonqualified benefits and welfare benefits provided to Executive immediately prior to the date on which a Change in Control occurs; *provided*, *however*, that a contemporaneous diminution of or reduction in qualified retirement benefits and/or welfare benefits which is of general application and which uniformly and contemporaneously reduces or diminishes the benefits of all covered employees shall be ignored and not be considered a reduction in remuneration for purposes of this paragraph (d);

(e) a reduction in Executive's overall compensation opportunities (as contrasted with overall compensation actually paid or awarded) under the STI Plan, a long-term incentive plan or other equity plan (or in such substitute or alternative plans) from that provided to Executive immediately prior to the date on which a Change in Control occurs;

(f) a change in the location of Executive's principal place of employment with the Company by more than 50 miles from the location where Executive was principally employed immediately prior to the date on which a Change in Control occurs; or

(g) a failure by the Company to provide directors and officers liability insurance covering Executive comparable to that provided to Executive immediately prior to the date on which a Change in Control occurs;

provided, *however*, that no later than 15 days after learning of the action (or inaction) described herein as the basis for a termination of employment for Good Reason, Executive shall advise the Company in writing that the action (or inaction) constitutes grounds for a termination of his employment for Good Reason, in which event the Company shall have 30 days to correct such action (or inaction) and if such action (or inaction) is timely corrected, then Executive shall not be entitled to terminate his employment for Good Reason as a result of such action (or inaction).

"Retirement Plan" mean the CenterPoint Energy, Inc. Retirement Plan, as amended and restated effective January 1, 1999, and as thereafter amended.

"STI Plan" means the CenterPoint Energy, Inc. Short Term Incentive Plan or any successor plan or program thereto.

"Target Bonus" means Executive's target incentive award opportunity under the STI Plan in effect for the year with respect to which the target bonus amount is being determined or, if no such plan is then in effect, for the last year in which such a plan was in effect, expressed as a dollar amount based upon Executive's annual base salary for the year of such determination.

"Waiver and Release" means a legal document, in the form attached hereto as *Exhibit A* or such other form as may be prescribed by the Company, but which form may not be altered, amended or modified after execution of a binding agreement to effect a Change in Control without the consent of Executive, in which Executive, in exchange for severance benefits described in Section 2, among other things, releases the Company, the Affiliates, their directors, officers, employees and agents, their employee benefit plans and the fiduciaries and agents of said plans from liability and damages in any way related to Executive's employment with or separation from the Company or any of its Affiliates.

"Welfare Benefit Coverage" means each of medical, dental and vision benefit coverage.

2. **Severance Benefits:** If Executive experiences a Covered Termination, then Executive shall be entitled to receive, as additional compensation for services rendered to the Company (including its Affiliates), subject to the execution and return to the Company of a Waiver and Release within 50 days following the date of Executive's Covered Termination that is not revoked within the seven-day period following such execution date (the "Waiver and Release Revocation Period"), the following severance benefits:

(a) ***Severance Amount***: A lump sum cash payment in an amount equal to Executive's Compensation multiplied by three, subject to applicable withholding for income and employment taxes. Such severance payment shall be paid on the date following six months after the date of Executive's Covered Termination, along with simple interest on the severance amount at the short-term applicable Federal rate provided for in Code Section 7872(f)(2)(A), based on the period the payment was delayed from the Covered Termination date.

(b) ***Vacation Payment***: A lump sum cash payment in an amount equal to his earned, but not taken, vacation days through the date of Executive's Covered Termination, subject to applicable withholding for income and employment taxes. Such vacation payment shall be paid as soon as practicable following his Covered Termination date in accordance with the Company's normal payroll policies and practices.

(c) ***Pro-Rated Bonus***: A lump sum cash payment in an amount equal to the Target Bonus in effect at the time of Executive's Covered Termination based on Executive's eligible earnings under the STI Plan as of the date of his Covered Termination, but reduced by any amount payable under the terms of the STI Plan for the performance year in which the Change in Control is consummated, subject to applicable withholding for income and employment taxes. Such pro-rated bonus shall be paid on the date following six months after the date of Executive's Covered Termination, along with simple interest on the bonus amount at the short-term applicable Federal rate provided for in Code Section 7872(f)(2)(A), based on the period the payment was delayed from the Covered Termination date.

(d) ***Welfare Benefit Coverage***: Subject to Executive's payment of applicable premiums on the same basis as similarly situated active executives of the Company, continued Welfare Benefit Coverage for Executive and his eligible dependents for a period of two years following the date of Executive's Covered Termination.

(e) ***Outplacement***: Outplacement services for a 9-month period after the date of Executive's Covered Termination in connection with Executive's efforts to obtain new employment under the outplacement program adopted by the Company. Executive shall not be entitled to a cash payment in lieu of such services.

(f) ***Benefit Restoration Plan***: Benefits pursuant to the Company's Benefit Restoration Plan in which Executive is a participant in an amount not less than the amount that Executive would have been entitled to receive pursuant to the Retirement Plan and the Benefit Restoration Plan (i) if Executive were fully vested in his Retirement Plan benefits and (ii) had Executive remained an employee of the Company or its Affiliates throughout the three-year period following the date of the Change in Control (*provided*, *however*, that in no event shall this clause (ii) cause Executive to have more than 35 years of service for purposes of the Benefit Restoration Plan). If Executive's Retirement Plan benefit is pursuant to the cash balance formula, his annual compensation for each of the three years following the Change in Control shall be based on his Compensation. The Company agrees to amend the Benefit Restoration Plan to the extent necessary to provide for the payment of this benefit, which shall be offset by, and not in addition to, any benefit actually payable pursuant to the qualified Retirement Plan. Such benefit shall be paid in accordance with the terms and conditions of the Benefit Restoration Plan.

(g) ***All Other Benefit Plans or Programs***: Executive's participation in all other employee benefit plans and/or programs at the Company and the Affiliates shall cease as of Executive's Covered Termination date, subject to the terms and conditions of the governing documents of those employee benefit plans and/or programs.

3. **Certain Additional Payments:** Anything in this Agreement to the contrary notwithstanding and except as set forth below, in the event it shall be determined that any payment or distribution in the nature of compensation (within the meaning of Section 280G(b)(2) of the Code) to or for the benefit of Executive, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise, but determined without regard to any additional payments required under this Section 3 (the "Payment"), would be subject to the excise tax imposed by Section 4999 of the Code, together with any interest or penalties imposed with respect to such excise tax ("Excise Tax"), then Executive shall be entitled to receive an additional payment (a "Gross-Up Payment") in an amount such that, after payment (whether through withholding at the source or otherwise) by Executive of all taxes (including any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto), employment taxes and Excise Tax imposed upon the Gross-Up Payment, Executive retains an amount of the Gross-Up Payment equal to the Excise Tax imposed upon the Payment. Notwithstanding the foregoing provision of this Section 3, if the Company determines that by reducing the Payment by an amount not to exceed 10% of the Payment ("Reduced Amount") the receipt of the Payment will not give rise to any Excise Tax, and thus no Gross-Up Payment would be required to be made to Executive, then the amount of the Payment shall be reduced by the minimum Reduced Amount

necessary, with such reduction to be made from the amounts payable under Section 2(a) and (c), to avoid any Excise Tax and no Gross-Up Payment shall be required under this Section 3 or the Agreement.

Subject to the provisions of this Section 3, all determinations required to be made under this Section 3, including whether and when a Gross-Up Payment is required and the amount of such Gross-Up Payment and the assumptions to be utilized in arriving at such determination, shall be made by a nationally recognized certified public accounting firm that is selected by the Company (the “Accounting Firm”) which shall provide detailed supporting calculations both to the Company and Executive within 15 business days after the receipt of notice from Executive that there has been a Payment, or such earlier time as is requested by the Company. In the event that the Accounting Firm is serving as accountant or auditor for the individual, entity or group effecting the Change in Control or the Accounting Firm declines or is unable to serve, Executive shall appoint another nationally recognized certified public accounting firm to make the determinations required hereunder (which accounting firm shall then be referred to as the Accounting Firm hereunder). All fees and expenses of the Accounting Firm shall be borne solely by the Company. Any Gross-Up Payment, as determined pursuant to this Section 3, shall be paid by the Company to Executive within 15 days after the receipt of the Accounting Firm’s determination. If the Accounting Firm determines that no Excise Tax is payable by Executive, it shall furnish Executive with a written opinion that failure to report the Excise Tax on Executive’s applicable federal income tax return would not result in the imposition of negligence or similar penalty. Any determination by the Accounting Firm shall be binding upon the Company and Executive. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Gross-Up Payments which will not have been made by the Company should have been made (“Underpayment”), consistent with the calculations required to be made hereunder. In the event that the Company exhausts its remedies pursuant to the following provisions of this Section 3 and Executive thereafter is required to make a payment of any Excise Tax, the Accounting Firm shall determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Company to or for the benefit of Executive no later than December 31st of the year following the year during which Executive remits the related taxes, *provided however*, that in no event shall such Underpayment be made to Executive until after the 6-month period commencing on the date of Executive’s Covered Termination.

Executive shall notify the Company in writing of any claim by the Internal Revenue Service that, if successful, would require the payment by the Company of the Gross-Up Payment. Such notification shall be given as soon as practicable but no later than 10 business days after Executive is informed in writing of such claim and shall apprise the Company of the nature of such claim and the date on which such claim is requested to be paid. Executive shall not pay such claim prior to the expiration of the 30-day period following the date on which it gives such notice to the Company (or such shorter period ending on the date that any payment of taxes with respect to such claim is due). If the Company notifies Executive in writing prior to the expiration of such period that it desires to contest such claim, Executive shall:

(a) give the Company any information reasonably requested by the Company relating to such claim;

(b) take such action in connection with contesting such claim as the Company shall reasonably request in writing from time to time, including, without limitation, accepting legal representation with respect to such claim by an attorney reasonably selected by the Company;

(c) cooperate with the Company in good faith in order to effectively contest such claim; and

(d) permit the Company to participate in any proceedings relating to such claim;

provided, however, that the Company shall bear and pay directly all costs and expenses (including additional interest and penalties) incurred in connection with such contest and shall indemnify and hold Executive harmless, on an after-tax basis, for any Excise Tax, employment tax or income tax (including interest and penalties with respect thereto) imposed as a result of such representation and payment of costs and expenses. Without limitation of the foregoing provisions of this Section 3, the Company shall control all proceedings taken in connection with such contest and, at its sole option, may pursue or forgo any and all administrative appeals, proceedings, hearings and conferences with the taxing authority in respect of such claim and may, at its sole option, either direct Executive to pay the tax claimed and sue for a refund or contest the claim in any permissible manner, and Executive agrees to prosecute such contest to a determination before any administrative tribunal, in a court of initial jurisdiction and in one or more appellate courts, as the Company shall determine; *provided, however*, that if the Company directs Executive to pay such claim and sue for a refund, the Company shall provide the amount of such payment to Executive as an additional payment ("Supplemental Payment") (subject to possible repayment as provided in the next paragraph) and shall indemnify and hold Executive harmless, on an after-tax basis, from any Excise Tax, employment tax or income tax (including interest or penalties with respect thereto) imposed with respect to such payment or with respect to any imputed income with respect thereto; and further provided that any extension of the statute of limitations relating to payment of taxes for the taxable year of Executive with respect to which such contested amount is claimed to be due is limited solely to such contested amount. Furthermore, the Company's control of the contest shall be limited to issues with respect to which a Gross-Up Payment or Supplemental Payment would be payable hereunder and Executive shall be entitled to settle or contest, as the case may be, any other issue raised by the Internal Revenue Service or any other taxing authority.

If, after the receipt by Executive of an amount provided by the Company pursuant to the foregoing provisions of this Section 3, Executive becomes entitled to receive any refund with respect to such claim, Executive shall (subject to the Company complying with the requirements of this Section 3) promptly pay to the Company the amount of such refund (together with any interest paid or credited thereon after taxes applicable thereto).

If the Company is obligated to provide Executive with one or more Welfare Benefit Coverages pursuant to Section 2(d), and the amount of such benefits or the value of such benefit coverage (including, without limitation, any insurance premiums paid by the Company to provide such benefits) is subject to any income, employment or similar tax imposed by federal, state or local law, or any interest or penalties with respect to such tax (such tax or taxes, together with any such interest and penalties, being hereafter collectively referred to as the "Income Tax") because such benefits cannot be provided under a nondiscriminatory health plan described in Section 105 of the Code or for any other reason, the Company will pay to Executive an additional payment or payments (collectively, an "Income Tax Payment"). The Income Tax Payment will be in an amount such that, after payment by Executive of all taxes (including any interest or penalties imposed with respect to such taxes), Executive retains an amount of the Income Tax Payment equal to the Income Tax imposed with respect to such welfare benefits or such welfare benefit coverage.

4. **Legal Fees And Expenses:** It is the intent of the Company that Executive not be required to incur legal fees and the related expenses associated with the interpretation, enforcement or defense of Executive's rights under this Agreement by litigation or otherwise because the cost and expense thereof would detract from the benefits intended to be extended to Executive hereunder. Accordingly, if it should appear to Executive that the Company has failed to comply with any of its obligations under this Agreement or in the event that the Company or any other person takes or threatens to take any action to declare this Agreement void or unenforceable, or institutes any litigation or other action or proceeding designed to deny, or to recover from, Executive the benefits provided or intended to be provided to Executive hereunder, the Company irrevocably authorizes Executive from time to time to retain counsel of Executive's choice, at the expense of the Company as hereafter provided, to advise and represent Executive in connection with any such interpretation, enforcement or defense, including, without limitation, the initiation or defense of any litigation or other legal action, whether by or against the Company or any director, officer, stockholder or other person affiliated with the Company, in any jurisdiction. Notwithstanding any existing or prior attorney-client relationship between the Company and such counsel, the Company irrevocably consents to Executive entering into an attorney-client relationship with such counsel, and in that connection the Company and Executive agree that a confidential relationship will exist between Executive and such counsel. Without regard to whether Executive prevails, in whole or in part, in connection with any of the foregoing, the Company will pay and be solely financially responsible for any and all attorneys' fees and related expenses incurred by Executive in connection with any of the foregoing except to the extent that a final judgment no longer subject to appeal finds that a claim or defense asserted by Executive was frivolous. In such a case, the portion of such fees and expenses incurred by Executive as a result of such frivolous claim or defense shall become Executive's sole responsibility and any funds advanced by the Company shall be repaid to the Company.

With respect to the Company's obligations under this Section 4, the fees and expenses of counsel selected by Executive pursuant to this Section 4 will be paid, or reimbursed to Executive if paid by Executive, on a regular, periodic basis upon presentation by Executive to the Company of a statement or statements prepared by such counsel in accordance with its customary practices, with such payment to be made no later than March 15th of the year following the year in which the expenses are incurred. The pendency of a claim by the Company that a claim or defense of Executive is frivolous or otherwise lacking merit shall not excuse the Company from making periodic payments of legal fees and expenses until a final judgment is rendered as hereinabove provided. Any failure by the Company to satisfy any of its obligations under this Section 4 will not limit the rights of Executive hereunder. Subject to the foregoing, Executive will have the status of a general unsecured creditor of the Company and will have no right to, or security interest in, any assets of the Company or any Affiliate.

5. **Confidentiality:** Executive acknowledges that pursuant to this Agreement, the Company agrees to provide to him Confidential Information regarding the Company and the Company's business and has previously provided him other such Confidential Information. In return for this and other consideration, provided under this Agreement, Executive agrees that he will not, while employed by the Company and thereafter, disclose or make available to any other person or entity, or use for his own personal gain, any Confidential Information, except for such disclosures as required in the performance of his duties hereunder as may otherwise be required by law or legal process (in which case Executive shall notify the Company of such legal or judicial proceeding as soon as practicable following his receipt of notice of such a proceeding, and permit the Company to seek to protect its interests and information). For purposes of this Agreement, "Confidential Information" shall mean any and all information, data and knowledge that has been created, discovered, developed or otherwise become known to the Company or any of its Affiliates or ventures or in which property rights have been assigned or otherwise conveyed to the Company or any of its Affiliates or ventures, which information, data or knowledge has commercial value in the business in which the Company is engaged, except such information, data or knowledge as is or becomes known to the public without violation of the terms of this Agreement. By way of illustration, but not limitation, Confidential Information includes business trade secrets, secrets concerning the Company's plans and strategies, nonpublic information concerning material market opportunities, technical trade secrets, processes, formulas, know-how, improvements, discoveries, developments, designs, inventions, techniques, marketing plans, manuals, records of research, reports, memoranda, computer software, strategies, forecasts, new products, unpublished financial information, projections, licenses, prices, costs, and employee, customer and supplier lists or parts thereof.

6. **Return Of Property:** Executive agrees that at the time of leaving the Company's employ, he will deliver to the Company (and will not keep in his possession, recreate or deliver to anyone else) all Confidential Information as well as all other devices, records, data, notes, reports, proposals, lists, correspondence, specifications, drawings, blueprints, sketches, materials, equipment, customer or client lists or information, or any other documents or property (including all reproductions of the aforementioned items) belonging to the Company or any of its Affiliates or ventures, regardless of whether such items were prepared by Executive.

7. **Non-Solicitation And Non-Competition:**

(a) For consideration provided under this Agreement, including, but not limited to the Company's agreement to provide Executive with Confidential Information (as defined in Section 5) regarding the Company and the Company's business, Executive agrees that while employed by the Company and for one year following a Covered Termination he shall not, without the prior written consent of the Company, directly or indirectly, (i) hire or induce, entice or solicit (or attempt to induce, entice or solicit) any employee of the Company or any of its Affiliates or ventures to leave the employment of the Company or any of its Affiliates or ventures or (ii) solicit or attempt to solicit the business of any customer or acquisition prospect of the Company or any of its Affiliates or ventures with whom Executive had any actual contact while employed at the Company.

(b) Additionally, for consideration provided under this Agreement, including, but not limited to the Company's agreement to provide Executive with Confidential Information regarding the Company and the Company's business, Executive agrees that while employed by the Company and for one year following a Covered Termination he will not, without the prior written consent of the Company, acting alone or in conjunction with others, either directly or indirectly, engage in any business that is in competition with the Company or accept employment with or render services to such a business as an officer, agent, employee, independent contractor or consultant, or otherwise engage in activities that are in competition with the Company.

(c) The restrictions contained in this Section 7 are limited to a 50-mile radius around any geographical area in which the Company engages (or has definite plans to engage) in operations or the marketing of its products or services at the time of a Covered Termination.

(d) Executive acknowledges that these restrictive covenants under this Agreement, for which Executive received valuable consideration from the Company as provided in this Agreement, including, but not limited to the Company's agreement to provide Executive with Confidential Information regarding the Company and the Company's business are ancillary to otherwise enforceable provisions of this Agreement that the consideration provided by the Company gives rise to the Company's interest in restraining Executive from competing and that the restrictive covenants are designed to enforce Executive's consideration or return promises under this Agreement. Additionally, Executive acknowledges that these restrictive covenants contain limitations as to time, geographical area, and scope of activity to be restrained that are reasonable and do not impose a greater restraint than is necessary to protect the goodwill or other legitimate business interests of the Company, including, but not limited to, the Company's need to protect its Confidential Information.

8. **Conflicts With Other Agreements:** In the event that Executive becomes entitled to benefits under a prior or subsequent agreement pertaining to Executive's employment by the Company or any Affiliate thereof (other than this Agreement) or the benefits to which Executive is entitled as a result of such employment and such benefits conflict with the terms of this Agreement, Executive will receive the greater and more favorable of each of the benefits provided under either this Agreement or such other agreement or benefits, on an individual benefit basis.

9. **Notices:** For purposes of this Agreement, notices and all other communications provided for herein shall be in writing and shall be deemed to have been duly given when personally delivered or when mailed by United States registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to Company:	CenterPoint Energy, Inc. 1111 Louisiana Houston, Texas 77002 Attention: President and Chief Executive Officer
If to Executive:	**[NAME]** **[ADDRESS]** **[CITY, STATE, ZIP]**

or to such other address as either party may furnish to the other in writing in accordance herewith, except that notices of changes of address shall be effective only upon receipt.

10. **Litigation Assistance:** Executive agrees to assist the Company with any litigation matters related to the Company or any of its subsidiaries or affiliates as may be reasonably requested by the Company's General Counsel following the date of Executive's Covered Termination. The Company shall reimburse Executive for any reasonable travel or other business expenses incurred in connection with providing such assistance and cooperation. Executive shall provide such services as an independent contractor and such services shall be limited solely to those matters with which Executive is suitably experienced and knowledgeable by reason of Executive's education, training, background and prior employment with the Company. The Company and Executive agree to work out reasonable accommodations for the provision of such assistance so that it does not unreasonably interfere with any of Executive's personal affairs, business endeavors or future employment. The foregoing notwithstanding, the Company and Executive agree that the services provided by Executive under this Section, if any, shall not exceed twenty percent (20%) of the average level of bona fide services performed by Executive (whether as an employee or an independent contractor of the Company) over the 36-month period (or the full period of services to the Company if Executive has been providing services to the Company for less than 36 months) immediately preceding his Covered Termination date.

11. **Prior Agreements/Modification:** This Agreement contains the entire agreement between the parties with respect to the subject matter hereof and supersedes all prior agreements or understandings, whether written or oral, between the parties with respect thereto. This Agreement may be amended only by an agreement in writing signed by the parties hereto; *provided*, *however*, that Executive's compensation may be increased at any time by the Company without in any way affecting any of the other terms and conditions of this Agreement which in all other respects shall remain in full force and effect. Notwithstanding the foregoing to the contrary, to the extent permitted under Code Section 409A and the regulations and guidance issued thereunder ("Section 409A"), the Company may amend the definition of a Change in Control under this Agreement to be compliant with the definition of a "change in control" under Code Section 409A, as the Company determines is appropriate in its sole discretion, without the consent of Executive. The provisions of this Agreement will be binding upon, and will inure to the benefit of, the respective heirs, legal representatives and successors of the parties hereto. Executive represents to the Company that he is not a party to any agreement or subject to any legal restriction that would prevent him from fulfilling his duties hereunder.

12. **Section 409A:** The Company and Executive mutually desire to avoid imposition of an excise tax under Section 409A. Accordingly, if any provision provided herein results in the imposition of an excise tax under the provisions of Section 409A, the parties agree to fully cooperate in good faith and take appropriate reasonable actions to amend and/or operate the Agreement to avoid any such imposition as Executive and the Company determine is appropriate to comply with Section 409A. Notwithstanding any provision of this Agreement to the contrary, the parties agree that any benefit or benefits under this Agreement that the Company determines are subject to the suspension period under Code Section 409A(a)(2)(B) shall not be paid or commence until a date following six months after Executive's Covered Termination date, or if earlier, Executive's death.

All reimbursements and in-kind benefits provided pursuant to this Agreement shall be made in accordance with Treasury Regulations Section 1.409A-3(i)(1)(iv) such that any reimbursements or in-kind benefits will be deemed payable at a specified time or on a fixed schedule relative to a permissible payment event. Specifically, (a) the amounts reimbursed and in-kind benefits under this Agreement, other than with respect to medical benefits provided under Section 2(d), during Executive's taxable year may not affect the amounts reimbursed or in-kind benefits provided in any other taxable year, (b) the reimbursement of an eligible expense shall be made on or before the last day of Executive's taxable year following the taxable year in which the expense was incurred, and (c) the right to reimbursement or an in-kind benefit is not subject to liquidation or exchange for another benefit.

13. **Applicable Law:** The validity, interpretation, construction and performance of this Agreement will be governed by and construed in accordance with the substantive laws of the State of Texas, including the Texas statute of limitations, but without giving effect to the principles of conflict of laws of such State.

14. **Severability:** If a court of competent jurisdiction determines that any provision of this Agreement is invalid or unenforceable, then the invalidity or unenforceability of that provision shall not affect the validity or enforceability of any other provision of this Agreement and all other provisions shall remain in full force and effect.

15. **Withholding of Taxes:** The Company may withhold from any benefits payable under this Agreement all federal, state, city or other taxes as may be required pursuant to any law or governmental regulation or ruling.

16. **No Employment Agreement:** Nothing in this Agreement shall give Executive any rights to (or impose any obligations for) continued employment by the Company or any Affiliate thereof or successor thereto, nor shall it give the Company any rights (or impose any obligations) with respect to continued performance of duties by Executive for the Company or any Affiliate thereof or successor thereto.

17. **No Assignment; Successors:** Executive's right to receive payments or benefits hereunder shall not be assignable or transferable, whether by pledge, creation or a security interest or otherwise, whether voluntary, involuntary, by operation of law or otherwise, other than a transfer by will or by the laws of descent or distribution, and in the event of any attempted assignment or transfer contrary to this Section 17, the Company shall have no liability

to pay any amount so attempted to be assigned or transferred. This Agreement shall inure to the benefit of and be enforceable by Executive's personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees and legatees.

This Agreement shall be binding upon and inure to the benefit of the Company, its successors and assigns (including, without limitation, any company into or with which the Company may merge or consolidate). The Company agrees that it will not effect the sale or other disposition of all or substantially all of its assets unless either (a) the person or entity acquiring such assets or a substantial portion thereof shall expressly assume by an instrument in writing all duties and obligations of the Company hereunder or (b) the Company shall provide, through the establishment of a separate reserve therefor, for the payment in full of all amounts which are or may reasonably be expected to become payable to Executive hereunder.

18. **Payment Obligations Absolute:** Except for the requirement of Executive to execute and return to the Company a Waiver and Release in accordance with Section 2, the Company's obligation to pay (or cause one of its Affiliates to pay) Executive the amounts and to make the arrangements provided herein shall be absolute and unconditional and shall not be affected by any circumstances, including, without limitation, any set-off, counter-claim, recoupment, defense or other right which the Company (including its Affiliates) may have against him or anyone else. All amounts payable by the Company (including its Affiliates hereunder) shall be paid without notice or demand. Executive shall not be obligated to seek other employment in mitigation of the amounts payable or arrangements made under any provision of this Agreement, and, subject to the restrictions in Section 7, the obtaining of any other employment shall in no event affect any reduction of the Company's obligations to make (or cause to be made) the payments and arrangements required to be made under this Agreement.

The Company will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place. As used in this Agreement, "Company" shall mean the Company as hereinbefore defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform this Agreement by operation of law, or otherwise. If a Business Combination is consummated that would have resulted in a Change in Control but for the satisfaction of the conditions specified in clauses (i), (ii), (iii) and (iv) of subsection (c) of the definition of "Change in Control" in Section 1 and if the Parent Corporation resulting from the Business Combination is other than the Company (hereinafter a "New Parent"), then, as a condition to consummation of this Business Combination, the New Parent shall be considered a successor for purposes of this paragraph.

19. **Number and Gender:** Wherever appropriate herein, words used in the singular shall include the plural and the plural shall include the singular. The masculine gender where appearing herein shall be deemed to include the feminine gender.

20. **Term:** The effective date of the Agreement is January 1, 2008 ("Effective Date"). The term of this Agreement shall commence on the Effective Date and shall end on December 31, 2008; *provided, however*, that on each January 1st thereafter, the term of this

Agreement shall automatically be extended for one additional year unless, prior to any such January 1st, the Board decides not to extend the term of this Agreement, in which event the term shall, without further action, expire, and this Agreement shall terminate, on the December 31st of the year in which the Board makes such decision. The foregoing to the contrary notwithstanding, (a) if, prior to a Change in Control, Executive ceases for any reason other than due to a Covered Termination to be an employee of the Company, then the term shall, without further action, expire, and this Agreement shall terminate, as of such termination date; and (b) upon the Company entering into a binding agreement to effect a Change in Control, if the Agreement has not expired prior to such date, the term of this Agreement shall automatically be extended until the end of the two-year period commencing as of the date of the Change in Control; *provided, however*, that, the foregoing clause (b) notwithstanding, if the board of directors of the parties to such binding agreement agree, as evidenced by their resolutions, not to consummate the Change in Control, the term of this Agreement shall be determined as otherwise provided in this Section 20 without regard to clause (b).

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed and delivered as of the date first above written, but effective as of the Effective Date.

CENTERPOINT ENERGY, INC.

By: ______________________________

David M. McClanahan
President and Chief Executive Officer

EXECUTIVE

____

[NAME]

Waiver And Release

In exchange for the payment to me of the Severance Benefits described in Section 2 of the Change in Control Agreement between CenterPoint Energy, Inc., and me effective as of January 1, 2008 (the "Agreement"), which I understand is incorporated herein by reference, and of other remuneration and consideration provided for in the Agreement (the "Severance Benefits"), which is in addition to any remuneration or benefits to which I am already entitled, I agree to waive all of my claims against and release (i) CenterPoint Energy, Inc. and its predecessors, successors and assigns (collectively referred to as the "Company"), (ii) all of the affiliates (including, but not limited to, CenterPoint Energy Services Company, CenterPoint Energy Southern Gas Operations, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas Operations, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Oklahoma Gas, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas, CenterPoint Energy Houston Gas, CenterPoint Energy Pipeline Services, Inc., CenterPoint Energy Services, Inc., CenterPoint Energy Field Services, Inc., CenterPoint Energy Gas Transmission Company, CenterPoint Energy Mississippi River Transmission Corporation, and all wholly or partially owned subsidiaries) of the Company and their predecessors, successors and assigns (collectively referred to as the "Company Affiliates") and (iii) the Company's and Company Affiliates' directors and officers, employees and agents, insurers, employee benefit plans and the fiduciaries and agents of the foregoing (collectively, with the Company and Company Affiliates, referred to as the "Corporate Group") from any and all claims, demands, actions, liabilities and damages arising out of or relating in any way to my employment with or separation from the Company or the Company Affiliates. All payments under the Agreement are voluntary and are not required by any legal obligation other than the Agreement itself.

I understand that signing this Waiver and Release is an important legal act. I acknowledge that I have been advised in writing to consult an attorney before signing this Waiver and Release. I understand that, in order to be eligible for Severance Benefits under the Agreement, I must sign and return (to Carol Helliker, Vice President, Corporate Compliance Officer and Associate General Counsel, Legal Department, at CenterPoint Energy Tower, 46th Floor, 1111 Louisiana, Houston, Texas 77002) this Waiver and Release within 50 days following the date of my termination of employment. I acknowledge that I have been given at least 45 days to consider whether to execute this Waiver and Release.

In exchange for the payment to me of Severance Benefits pursuant to the Agreement, which is in addition to any remuneration or benefits to which I am already entitled, (1) I agree not to sue in any local, state and/or federal court or to file a grievance regarding or relating in any way to my employment with or separation from the Company or the Company Affiliates, and (2) I knowingly and voluntarily waive all claims and release the Corporate Group from any and all claims, demands, actions, liabilities, and damages, whether known or unknown, arising out of or relating in any way to my employment with or separation from the Company or the Company Affiliates, except to the extent that my rights are vested under the terms of employee benefit plans sponsored by the Company or the Company Affiliates and except with respect to such rights or claims as may arise after the date this Waiver and Release is executed. This Waiver and Release includes, but is not limited to, claims and causes of action under: Title

VII of the Civil Rights Act of 1964, as amended (“Title VII”); the Age Discrimination in Employment Act of 1967, as amended, including the Older Workers Benefit Protection Act of 1990 (“ADEA”); the Civil Rights Act of 1866, as amended; the Civil Rights Act of 1991; the Americans with Disabilities Act of 1990 (“ADA”); the Energy Reorganization Act, as amended, 42 U.S.C. § 5851; the Workers Adjustment and Retraining Notification Act of 1988; the Pregnancy Discrimination Act of 1978; the Employee Retirement Income Security Act of 1974, as amended; the Family and Medical Leave Act of 1993; the Fair Labor Standards Act; the Occupational Safety and Health Act; claims in connection with workers’ compensation or “whistle blower” statutes; and/or contract, tort, defamation, slander, wrongful termination or any other state or federal regulatory, statutory or common law. Further, I expressly represent that no promise or agreement which is not expressed in the Agreement or this Waiver and Release has been made to me in executing this Waiver and Release, and that I am relying on my own judgment in executing this Waiver and Release, and that I am not relying on any statement or representation of any member of the Corporate Group or any of their agents. I agree that this Waiver and Release is valid, fair, adequate and reasonable, is with my full knowledge and consent, was not procured through fraud, duress or mistake and has not had the effect of misleading, misinforming or failing to inform me. I acknowledge and agree that the Company will withhold any taxes required by federal or state law from the Severance Benefits otherwise payable to me and that the Severance Benefits otherwise payable to me shall be reduced by any monies owed by me to the Company (or a Company Affiliate), including, but not limited to, any overpayments made to me by the Company (or a Company Affiliate) and the balance of any loan by the Company (or a Company Affiliate) to me that is outstanding at the time that the Severance Benefits are paid.

I acknowledge that payment of Severance Benefits pursuant to the Agreement is not an admission by any member of the Corporate Group that they engaged in any wrongful or unlawful act or that any member of the Corporate Group violated any federal or state law or regulation. I understand that nothing in this Waiver and Release is intended to prohibit, restrict or otherwise discourage any individual from engaging in activity protected under 42 U.S.C. § 5851, 10 C.F.R. § 50.7 or the Sarbanes-Oxley Act of 2002, including, but not limited to, providing information to the Nuclear Regulatory Commission (“NRC”) or to any member of the Corporate Group regarding nuclear safety or quality concerns, potential violations or other matters within the NRC’s jurisdiction. I acknowledge that no member of the Corporate Group has promised me continued employment or represented to me that I will be rehired in the future. I acknowledge that my employer and I contemplate an unequivocal, complete and final dissolution of my employment relationship. I acknowledge that this Waiver and Release does not create any right on my part to be rehired by any member of the Corporate Group and I hereby waive any right to future employment by any member of the Corporate Group.

I have returned or I agree that I will return immediately, and maintain in strictest confidence and will not use in any way, any confidential and proprietary business information or other nonpublic information or documents relating to the business and affairs of the Corporate Group. For the purposes of this Waiver and Release, “confidential and proprietary business information” shall mean any information concerning any member of the Corporate Group or their business which I learn or develop during my employment and which is not generally known or available outside of the Corporate Group. Such information, without limitation, includes information, written or otherwise, regarding any member of the Corporate Group’s earnings, expenses, material sources, equipment sources, customers and prospective customers, business plans, strategies, practices and procedures, prospective and executed contracts and other business arrangements. I acknowledge and agree that all records, papers, reports, computer programs, strategies, documents (including, without limitation, memoranda, notes, files and correspondence), opinions, evaluations, inventions, ideas, technical data, products, services, processes, procedures, and interpretations that are or have been produced by me or any employee, officer, director, agent, contractor, or representative of any member of the Corporate Group, whether provided in written or printed form, or orally, all comprise confidential and proprietary business information. I agree that for a period of one year following my termination with the Corporate Group that I will not: (a) solicit, encourage or take any action that is intended, directly or indirectly, to induce any other employee of the Corporate Group to terminate employment with the Corporate Group; (b) interfere in any manner with the contractual or employment relationship between the Corporate Group and any other employee of the Corporate Group; and (c) use any confidential information to directly, or indirectly, solicit any customer of the Corporate Group. I understand and agree that in the event of any breach of the provisions of this paragraph, or threatened breach, by me, any member of the Corporate Group may, in their discretion, discontinue any or all payments provided for in the Agreement and recover any and all payments already made and any member of the Corporate Group shall be entitled to apply to a court of competent jurisdiction for such relief by way of specific performance, restraining order, injunction or otherwise as may be appropriate to ensure compliance with these provisions. Should I be contacted or served with legal process seeking to compel me to disclose any such information, I agree to notify the General Counsel of the Company immediately, in order that the Corporate Group may seek to resist such process if they so choose. If I am called upon to serve as a witness or consultant in or with respect to any potential litigation, litigation, arbitration, or regulatory proceeding, I agree to cooperate with the Corporate Group to the full extent permitted by law, and the Corporate Group agrees that any such call shall be with reasonable notice, shall not unnecessarily interfere with my later employment, and shall provide for payment for my time and costs expended in such matters.

Should any of the provisions set forth in this Waiver and Release be determined to be invalid by a court, agency or other tribunal of competent jurisdiction, it is agreed that such determination shall not affect the enforceability of other provisions of this Waiver and Release. I acknowledge that this Waiver and Release and the Agreement set forth the entire understanding and agreement between me and the Company or any other member of the Corporate Group concerning the subject matter of this Waiver and Release and supersede any prior or contemporaneous oral and/or written agreements or representations, if any, between me and the Company or any other member of the Corporate Group. I understand that for a period of 7 calendar days following the date I sign this Waiver and Release (which date must within 50 days following the date of my termination of employment), I may revoke my acceptance of the offer by delivering a written statement to the Vice President, Corporate Compliance Officer and Associate General Counsel (or the person designated by the Vice President, Corporate Compliance Officer and Associate General Counsel) by hand or by registered-mail, in which case the Waiver and Release will not become effective. In the event I revoke my acceptance of this offer, I shall not be entitled to any Severance Benefits under the Agreement. I understand that failure to revoke my acceptance of the offer within 7 calendar days following the date I sign this Waiver and Release will result in this Waiver and Release being permanent and irrevocable.

I acknowledge that I have read this Waiver and Release, have had an opportunity to ask questions and have it explained to me and that I understand that this Waiver and Release will have the effect of knowingly and voluntarily waiving any action I might pursue, including breach of contract, personal injury, retaliation, discrimination on the basis of race, age, sex, national origin, religion, veterans status, or disability and any other claims arising prior to the date of this Waiver and Release. By execution of this document, I do not waive or release or otherwise relinquish any legal rights I may have which are attributable to or arise out of acts, omissions, or events of any member of the Corporate Group which occur after the date of the execution of this Waiver and Release.

Executive's Printed Name	Corporate Group's Representative
Executive's Signature	Corporate Group's Execution Date
Executive's Signature Date	Executive's Social Security Number

CHANGE IN CONTROL AGREEMENT

THIS CHANGE IN CONTROL AGREEMENT ("Agreement") is made as of this ___day of December 2007, by and between CENTERPOINT ENERGY, INC., a Texas corporation (the "Company"), and **[NAME]** ("Executive").

1. **DEFINITIONS:**

All terms defined in this Section 1 shall, throughout this Agreement, have the meanings given herein:

"Affiliate" means any company controlled by, controlling or under common control with the Company within the meaning of Section 414 of the Code.

"Board" means the board of directors of the Company.

"Cause" means Executive's (a) gross negligence in the performance of Executive's duties, (b) intentional and continued failure to perform Executive's duties, (c) intentional engagement in conduct which is materially injurious to the Company or its Affiliates (monetarily or otherwise) or (d) conviction of a felony or a misdemeanor involving moral turpitude. For this purpose, an act or failure to act on the part of Executive will be deemed "intentional" only if done or omitted to be done by Executive not in good faith and without reasonable belief that his action or omission was in the best interest of the Company, and no act or failure to act on the part of Executive will be deemed "intentional" if it was due primarily to an error in judgment or negligence.

A **"Change in Control"** shall be deemed to have occurred upon the occurrence of any of the following events:

(a) ***30% Ownership Change***: Any Person makes an acquisition of Beneficial Ownership of Outstanding Voting Stock (including any acquisition of Beneficial Ownership deemed to have occurred pursuant to Rule 13d-5 under the Exchange Act) and is, immediately thereafter, the Beneficial Owner of 30% or more of the then Outstanding Voting Stock, unless such acquisition is made by a Parent Corporation resulting from a Business Combination (other than the Company) if, following such Business Combination, the conditions specified in clauses (i), (ii), (iii) and (iv) of subsection (c) of this definition are satisfied; or any Group is formed that is the Beneficial Owner of 30% or more of the Outstanding Voting Stock; or

(b) ***Board Majority Change***: Individuals who are Incumbent Directors cease for any reason to constitute a majority of the members of the Board; or

(c) ***Major Mergers and Acquisitions***: Approval by the shareholders of the Company of a Business Combination (or if there is no such approval by shareholders, consummation of such Business Combination) unless, immediately following such Business Combination, (i) all or substantially all of the individuals and entities that were the Beneficial Owners of the Outstanding Voting Stock immediately prior to such Business Combination will (or do) beneficially own, directly or indirectly, more than 70% of the then outstanding shares of voting stock of the Parent Corporation resulting from such Business Combination in substantially the same relative proportions as their ownership, immediately prior to such Business Combination, of the Outstanding Voting Stock, (ii) if the Business Combination involves the issuance or payment by the Company of consideration to another entity or its shareholders, the total fair market value of such consideration plus the principal amount of the consolidated long-term debt of the entity or business being acquired (in each case, determined as of the date of consummation of such Business Combination by a majority of the Incumbent Directors) will not (or does not) exceed 50% of the sum of the fair market value of the Outstanding Voting Stock plus the principal amount of the Company's consolidated long-term debt (in each case, determined immediately prior to such consummation by a majority of the Incumbent Directors), (iii) no Person (other than any Parent Corporation resulting from a Business Combination) will (or does) beneficially own, directly or indirectly, 30% or more of the then outstanding shares of voting stock of the Parent Corporation resulting from such Business Combination and (iv) a majority of the members of the board of directors of the Parent Corporation resulting from such Business Combination were Incumbent Directors immediately prior to consummation of such Business Combination; or

(d) ***Major Asset Dispositions***: Approval by the shareholders of the Company of a Major Asset Disposition (or if there is no such approval by shareholders consummation of such Major Asset Disposition) unless, immediately following such Major Asset Disposition, (i) individuals and entities that were Beneficial Owners of the Outstanding Voting Stock immediately prior to such Major Asset Disposition will (or do) beneficially own, directly or indirectly, more than 70% of the then outstanding shares of voting stock of the Company (if it continues to exist) and of the entity that acquires the largest portion of such assets (or the entity, if any, that owns a majority of the outstanding voting stock of such acquiring entity) and (ii) a majority of the members of the board of directors of the Company (if it continues to exist) and of the entity that acquires the largest portion of such assets (or the entity, if any, that owns a majority of the outstanding voting stock of such acquiring entity) were Incumbent Directors immediately prior to consummation of such Major Asset Disposition.

For purposes of the foregoing, the term:

(1) "Beneficial Owner," "Beneficial Ownership" and "Beneficially Own" are used as defined for purposes of Section 13(d)(3) under the Exchange Act.

(2) “Business Combination” means (x) a merger or consolidation involving the Company or its stock or (y) an acquisition by the Company, directly or through one or more subsidiaries, of another entity or its stock or assets.

(3) “Election Contest” is used as it is defined for purposes of Rule 14a-11 under the Exchange Act.

(4) “Exchange Act” means the Securities Exchange Act of 1934, as amended.

(5) “Group” is used as it is defined for purposes of Section 13(d)(3) of the Exchange Act.

(6) “Incumbent Director” means a director of the Company (x) who was a director of the Company on the date of this Agreement, or (y) who becomes a director subsequent to such date and whose election, or nomination for election by the Company’s shareholders, was approved by a vote of a majority of the Incumbent Directors at the time of such election or nomination, except that any such director shall not be deemed an Incumbent Director if his initial assumption of office occurs as a result of an actual or threatened Election Contest or other actual or threatened solicitation of proxies by or on behalf of a Person other than the Board.

(7) “Major Asset Disposition” means the sale or other disposition in one transaction or a series of related transactions of 70% or more of the assets of the Company and its subsidiaries on a consolidated basis; and any specified percentage or portion of the assets of the Company shall be based on fair market value, as determined by a majority of the Incumbent Directors.

(8) “Outstanding Voting Stock” means outstanding voting securities of the Company entitled to vote generally in the election of directors; and any specified percentage or portion of the Outstanding Voting Stock (or of other voting stock) shall be determined based on the combined voting power of such securities.

(9) “Parent Corporation resulting from a Business Combination” means the Company if its stock is not acquired or converted in the Business Combination and otherwise means the entity which as a result of such Business Combination owns the Company or all or substantially all of the Company’s assets either directly or through one or more subsidiaries.

(10) “Person” means an individual, entity or Group.

“Code” means the Internal Revenue Code of 1986, as amended.

“Common Stock” means the common stock, $0.01 par value, of the Company.

“Company” means CenterPoint Energy, Inc., a Texas corporation, and any successor thereto.

“Compensation” means the greater of (a) the sum of Executive’s annual base salary plus Target Bonus determined immediately prior to the date on which a Change in Control occurs, or (b) the sum of Executive’s annual base salary plus Target Bonus determined immediately prior to the date of his Covered Termination.

“Covered Termination” means any termination of Executive’s employment with the Company or any Affiliate that is a “Separation from Service” within the meaning of Code Section 409A and Treasury Regulation § 1.409A-1(h)(3) (or any successor regulations or guidance thereto) thereof:

(a) that does not result from any of the following:

(i) death;

(ii) disability entitling Executive to benefits under the Company’s long-term disability plan;

(iii) termination on or after age 65;

(iv) involuntary termination for Cause; or

(v) resignation by Executive, unless such resignation is for Good Reason; and

(b) that occurs:

(i) after the execution of a binding agreement to effect a Change in Control, subject to the Change in Control occurring; or

(ii) within two years after the date upon which a Change in Control occurs.

“Good Reason” means any one or more of the following:

(a) a failure to maintain Executive in the position, or a substantially equivalent position, with the Company and/or an Affiliate, as the case may be, which Executive held immediately prior to the Change in Control;

(b) a significant adverse change in the authorities, powers, functions, responsibilities or duties which Executive held immediately prior to the Change in Control;

(c) a reduction in Executive’s annual base salary as in effect immediately prior to the date on which a Change in Control occurs;

(d) a significant reduction in Executive's qualified retirement benefits, nonqualified benefits and welfare benefits provided to Executive immediately prior to the date on which a Change in Control occurs; *provided*, *however*, that a contemporaneous diminution of or reduction in qualified retirement benefits and/or welfare benefits which is of general application and which uniformly and contemporaneously reduces or diminishes the benefits of all covered employees shall be ignored and not be considered a reduction in remuneration for purposes of this paragraph (d);

(e) a reduction in Executive's overall compensation opportunities (as contrasted with overall compensation actually paid or awarded) under the STI Plan, a long-term incentive plan or other equity plan (or in such substitute or alternative plans) from that provided to Executive immediately prior to the date on which a Change in Control occurs;

(f) a change in the location of Executive's principal place of employment with the Company by more than 50 miles from the location where Executive was principally employed immediately prior to the date on which a Change in Control occurs; or

(g) a failure by the Company to provide directors and officers liability insurance covering Executive comparable to that provided to Executive immediately prior to the date on which a Change in Control occurs;

provided, *however*, that no later than 15 days after learning of the action (or inaction) described herein as the basis for a termination of employment for Good Reason, Executive shall advise the Company in writing that the action (or inaction) constitutes grounds for a termination of his employment for Good Reason, in which event the Company shall have 30 days to correct such action (or inaction) and if such action (or inaction) is timely corrected, then Executive shall not be entitled to terminate his employment for Good Reason as a result of such action (or inaction).

"Retirement Plan" mean the CenterPoint Energy, Inc. Retirement Plan, as amended and restated effective January 1, 1999, and as thereafter amended.

"STI Plan" means the CenterPoint Energy, Inc. Short Term Incentive Plan or any successor plan or program thereto.

"Target Bonus" means Executive's target incentive award opportunity under the STI Plan in effect for the year with respect to which the target bonus amount is being determined or, if no such plan is then in effect, for the last year in which such a plan was in effect, expressed as a dollar amount based upon Executive's annual base salary for the year of such determination.

"Waiver and Release" means a legal document, in the form attached hereto as *Exhibit A* or such other form as may be prescribed by the Company, but which form may not be altered, amended or modified after execution of a binding agreement to effect a Change in Control without the consent of Executive, in which Executive, in exchange for severance benefits described in Section 2, among other things, releases the Company, the Affiliates, their directors, officers, employees and agents, their employee benefit plans and the fiduciaries and agents of said plans from liability and damages in any way related to Executive's employment with or separation from the Company or any of its Affiliates.

"Welfare Benefit Coverage" means each of medical, dental and vision benefit coverage.

2. **Severance Benefits:** If Executive experiences a Covered Termination, then Executive shall be entitled to receive, as additional compensation for services rendered to the Company (including its Affiliates), subject to the execution and return to the Company of a Waiver and Release within 50 days following the date of Executive's Covered Termination that is not revoked within the seven-day period following such execution date (the "Waiver and Release Revocation Period"), the following severance benefits:

(a) ***Severance Amount***: A lump sum cash payment in an amount equal to Executive's Compensation multiplied by two, subject to applicable withholding for income and employment taxes. Such severance payment shall be paid on the date following six months after the date of Executive's Covered Termination, along with simple interest on the severance amount at the short-term applicable Federal rate provided for in Code Section 7872(f)(2)(A), based on the period the payment was delayed from the Covered Termination date.

(b) ***Vacation Payment***: A lump sum cash payment in an amount equal to his earned, but not taken, vacation days through the date of Executive's Covered Termination, subject to applicable withholding for income and employment taxes. Such vacation payment shall be paid as soon as practicable following his Covered Termination date in accordance with the Company's normal payroll policies and practices.

(c) ***Pro-Rated Bonus***: A lump sum cash payment in an amount equal to the Target Bonus in effect at the time of Executive's Covered Termination based on Executive's eligible earnings under the STI Plan as of the date of his Covered Termination, but reduced by any amount payable under the terms of the STI Plan for the performance year in which the Change in Control is consummated, subject to applicable withholding for income and employment taxes. Such pro-rated bonus shall be paid on the date following six months after the date of Executive's Covered Termination, along with simple interest on the bonus amount at the short-term applicable Federal rate provided for in Code Section 7872(f)(2)(A), based on the period the payment was delayed from the Covered Termination date.

(d) ***Welfare Benefit Coverage***: Subject to Executive's payment of applicable premiums on the same basis as similarly situated active executives of the Company, continued Welfare Benefit Coverage for Executive and his eligible dependents for a period of two years following the date of Executive's Covered Termination.

(e) ***Outplacement***: Outplacement services for a 9-month period after the date of Executive's Covered Termination in connection with Executive's efforts to obtain new employment under the outplacement program adopted by the Company. Executive shall not be entitled to a cash payment in lieu of such services.

(f) ***Benefit Restoration Plan***: Benefits pursuant to the Company's Benefit Restoration Plan in which Executive is a participant in an amount not less than the amount that Executive would have been entitled to receive pursuant to the Retirement Plan and the Benefit Restoration Plan (i) if Executive were fully vested in his Retirement Plan benefits and (ii) had Executive remained an employee of the Company or its Affiliates throughout the two-year period following the date of the Change in Control (*provided*, *however*, that in no event shall this clause (ii) cause Executive to have more than 35 years of service for purposes of the Benefit Restoration Plan). If Executive's Retirement Plan benefit is pursuant to the cash balance formula, his annual compensation for each of the two years following the Change in Control shall be based on his Compensation. The Company agrees to amend the Benefit Restoration Plan to the extent necessary to provide for the payment of this benefit, which shall be offset by, and not in addition to, any benefit actually payable pursuant to the qualified Retirement Plan. Such benefit shall be paid in accordance with the terms and conditions of the Benefit Restoration Plan.

(g) ***All Other Benefit Plans or Programs***: Executive's participation in all other employee benefit plans and/or programs at the Company and the Affiliates shall cease as of Executive's Covered Termination date, subject to the terms and conditions of the governing documents of those employee benefit plans and/or programs.

3. **Certain Additional Payments:** Anything in this Agreement to the contrary notwithstanding and except as set forth below, in the event it shall be determined that any payment or distribution in the nature of compensation (within the meaning of Section 280G(b)(2) of the Code) to or for the benefit of Executive, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise, but determined without regard to any additional payments required under this Section 3 (the "Payment"), would be subject to the excise tax imposed by Section 4999 of the Code, together with any interest or penalties imposed with respect to such excise tax ("Excise Tax"), then Executive shall be entitled to receive an additional payment (a "Gross-Up Payment") in an amount such that, after payment (whether through withholding at the source or otherwise) by Executive of all taxes (including any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto), employment taxes and Excise Tax imposed upon the Gross-Up Payment, Executive retains an amount of the Gross-Up Payment equal to the Excise Tax imposed upon the Payment. Notwithstanding the foregoing provision of this Section 3, if the Company determines that by reducing the Payment by an amount not to exceed 10% of the Payment ("Reduced Amount") the receipt of the Payment will not give rise to any Excise Tax, and thus no Gross-Up Payment would be required to be made to Executive, then the amount of the Payment shall be reduced by the minimum Reduced Amount

necessary, with such reduction to be made from the amounts payable under Section 2(a) and (c), to avoid any Excise Tax and no Gross-Up Payment shall be required under this Section 3 or the Agreement.

Subject to the provisions of this Section 3, all determinations required to be made under this Section 3, including whether and when a Gross-Up Payment is required and the amount of such Gross-Up Payment and the assumptions to be utilized in arriving at such determination, shall be made by a nationally recognized certified public accounting firm that is selected by the Company (the "Accounting Firm") which shall provide detailed supporting calculations both to the Company and Executive within 15 business days after the receipt of notice from Executive that there has been a Payment, or such earlier time as is requested by the Company. In the event that the Accounting Firm is serving as accountant or auditor for the individual, entity or group effecting the Change in Control or the Accounting Firm declines or is unable to serve, Executive shall appoint another nationally recognized certified public accounting firm to make the determinations required hereunder (which accounting firm shall then be referred to as the Accounting Firm hereunder). All fees and expenses of the Accounting Firm shall be borne solely by the Company. Any Gross-Up Payment, as determined pursuant to this Section 3, shall be paid by the Company to Executive within 15 days after the receipt of the Accounting Firm's determination. If the Accounting Firm determines that no Excise Tax is payable by Executive, it shall furnish Executive with a written opinion that failure to report the Excise Tax on Executive's applicable federal income tax return would not result in the imposition of negligence or similar penalty. Any determination by the Accounting Firm shall be binding upon the Company and Executive. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Gross-Up Payments which will not have been made by the Company should have been made ("Underpayment"), consistent with the calculations required to be made hereunder. In the event that the Company exhausts its remedies pursuant to the following provisions of this Section 3 and Executive thereafter is required to make a payment of any Excise Tax, the Accounting Firm shall determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Company to or for the benefit of Executive no later than December 31st of the year following the year during which Executive remits the related taxes, *provided however*, that in no event shall such Underpayment be made to Executive until after the 6-month period commencing on the date of Executive's Covered Termination.

Executive shall notify the Company in writing of any claim by the Internal Revenue Service that, if successful, would require the payment by the Company of the Gross-Up Payment. Such notification shall be given as soon as practicable but no later than 10 business days after Executive is informed in writing of such claim and shall apprise the Company of the nature of such claim and the date on which such claim is requested to be paid. Executive shall not pay such claim prior to the expiration of the 30-day period following the date on which it gives such notice to the Company (or such shorter period ending on the date that any payment of taxes with respect to such claim is due). If the Company notifies Executive in writing prior to the expiration of such period that it desires to contest such claim, Executive shall:

(a) give the Company any information reasonably requested by the Company relating to such claim;

(b) take such action in connection with contesting such claim as the Company shall reasonably request in writing from time to time, including, without limitation, accepting legal representation with respect to such claim by an attorney reasonably selected by the Company;

(c) cooperate with the Company in good faith in order to effectively contest such claim; and

(d) permit the Company to participate in any proceedings relating to such claim;

provided, *however*, that the Company shall bear and pay directly all costs and expenses (including additional interest and penalties) incurred in connection with such contest and shall indemnify and hold Executive harmless, on an after-tax basis, for any Excise Tax, employment tax or income tax (including interest and penalties with respect thereto) imposed as a result of such representation and payment of costs and expenses. Without limitation of the foregoing provisions of this Section 3, the Company shall control all proceedings taken in connection with such contest and, at its sole option, may pursue or forgo any and all administrative appeals, proceedings, hearings and conferences with the taxing authority in respect of such claim and may, at its sole option, either direct Executive to pay the tax claimed and sue for a refund or contest the claim in any permissible manner, and Executive agrees to prosecute such contest to a determination before any administrative tribunal, in a court of initial jurisdiction and in one or more appellate courts, as the Company shall determine; *provided*, *however*, that if the Company directs Executive to pay such claim and sue for a refund, the Company shall provide the amount of such payment to Executive as an additional payment ("Supplemental Payment") (subject to possible repayment as provided in the next paragraph) and shall indemnify and hold Executive harmless, on an after-tax basis, from any Excise Tax, employment tax or income tax (including interest or penalties with respect thereto) imposed with respect to such payment or with respect to any imputed income with respect thereto; and further provided that any extension of the statute of limitations relating to payment of taxes for the taxable year of Executive with respect to which such contested amount is claimed to be due is limited solely to such contested amount. Furthermore, the Company's control of the contest shall be limited to issues with respect to which a Gross-Up Payment or Supplemental Payment would be payable hereunder and Executive shall be entitled to settle or contest, as the case may be, any other issue raised by the Internal Revenue Service or any other taxing authority.

If, after the receipt by Executive of an amount provided by the Company pursuant to the foregoing provisions of this Section 3, Executive becomes entitled to receive any refund with respect to such claim, Executive shall (subject to the Company complying with the requirements of this Section 3) promptly pay to the Company the amount of such refund (together with any interest paid or credited thereon after taxes applicable thereto).

If the Company is obligated to provide Executive with one or more Welfare Benefit Coverages pursuant to Section 2(d), and the amount of such benefits or the value of such benefit coverage (including, without limitation, any insurance premiums paid by the Company to provide such benefits) is subject to any income, employment or similar tax imposed by federal, state or local law, or any interest or penalties with respect to such tax (such tax or taxes, together with any such interest and penalties, being hereafter collectively referred to as the “Income Tax”) because such benefits cannot be provided under a nondiscriminatory health plan described in Section 105 of the Code or for any other reason, the Company will pay to Executive an additional payment or payments (collectively, an “Income Tax Payment”). The Income Tax Payment will be in an amount such that, after payment by Executive of all taxes (including any interest or penalties imposed with respect to such taxes), Executive retains an amount of the Income Tax Payment equal to the Income Tax imposed with respect to such welfare benefits or such welfare benefit coverage.

4. **Legal Fees And Expenses:** It is the intent of the Company that Executive not be required to incur legal fees and the related expenses associated with the interpretation, enforcement or defense of Executive’s rights under this Agreement by litigation or otherwise because the cost and expense thereof would detract from the benefits intended to be extended to Executive hereunder. Accordingly, if it should appear to Executive that the Company has failed to comply with any of its obligations under this Agreement or in the event that the Company or any other person takes or threatens to take any action to declare this Agreement void or unenforceable, or institutes any litigation or other action or proceeding designed to deny, or to recover from, Executive the benefits provided or intended to be provided to Executive hereunder, the Company irrevocably authorizes Executive from time to time to retain counsel of Executive’s choice, at the expense of the Company as hereafter provided, to advise and represent Executive in connection with any such interpretation, enforcement or defense, including, without limitation, the initiation or defense of any litigation or other legal action, whether by or against the Company or any director, officer, stockholder or other person affiliated with the Company, in any jurisdiction. Notwithstanding any existing or prior attorney-client relationship between the Company and such counsel, the Company irrevocably consents to Executive entering into an attorney-client relationship with such counsel, and in that connection the Company and Executive agree that a confidential relationship will exist between Executive and such counsel. Without regard to whether Executive prevails, in whole or in part, in connection with any of the foregoing, the Company will pay and be solely financially responsible for any and all attorneys’ fees and related expenses incurred by Executive in connection with any of the foregoing except to the extent that a final judgment no longer subject to appeal finds that a claim or defense asserted by Executive was frivolous. In such a case, the portion of such fees and expenses incurred by Executive as a result of such frivolous claim or defense shall become Executive’s sole responsibility and any funds advanced by the Company shall be repaid to the Company.

With respect to the Company’s obligations under this Section 4, the fees and expenses of counsel selected by Executive pursuant to this Section 4 will be paid, or reimbursed to Executive if paid by Executive, on a regular, periodic basis upon presentation by Executive to the Company of a statement or statements prepared by such counsel in accordance with its customary practices, with such payment to be made no later than March 15th of the year following the year in which the expenses are incurred. The pendency of a claim by the Company that a claim or defense of Executive is frivolous or otherwise lacking merit shall not excuse the Company from making periodic payments of legal fees and expenses until a final judgment is rendered as hereinabove provided. Any failure by the Company to satisfy any of its obligations under this Section 4 will not limit the rights of Executive hereunder. Subject to the foregoing, Executive will have the status of a general unsecured creditor of the Company and will have no right to, or security interest in, any assets of the Company or any Affiliate.

5. **Confidentiality:** Executive acknowledges that pursuant to this Agreement, the Company agrees to provide to him Confidential Information regarding the Company and the Company's business and has previously provided him other such Confidential Information. In return for this and other consideration, provided under this Agreement, Executive agrees that he will not, while employed by the Company and thereafter, disclose or make available to any other person or entity, or use for his own personal gain, any Confidential Information, except for such disclosures as required in the performance of his duties hereunder as may otherwise be required by law or legal process (in which case Executive shall notify the Company of such legal or judicial proceeding as soon as practicable following his receipt of notice of such a proceeding, and permit the Company to seek to protect its interests and information). For purposes of this Agreement, "Confidential Information" shall mean any and all information, data and knowledge that has been created, discovered, developed or otherwise become known to the Company or any of its Affiliates or ventures or in which property rights have been assigned or otherwise conveyed to the Company or any of its Affiliates or ventures, which information, data or knowledge has commercial value in the business in which the Company is engaged, except such information, data or knowledge as is or becomes known to the public without violation of the terms of this Agreement. By way of illustration, but not limitation, Confidential Information includes business trade secrets, secrets concerning the Company's plans and strategies, nonpublic information concerning material market opportunities, technical trade secrets, processes, formulas, know-how, improvements, discoveries, developments, designs, inventions, techniques, marketing plans, manuals, records of research, reports, memoranda, computer software, strategies, forecasts, new products, unpublished financial information, projections, licenses, prices, costs, and employee, customer and supplier lists or parts thereof.

6. **Return Of Property:** Executive agrees that at the time of leaving the Company's employ, he will deliver to the Company (and will not keep in his possession, recreate or deliver to anyone else) all Confidential Information as well as all other devices, records, data, notes, reports, proposals, lists, correspondence, specifications, drawings, blueprints, sketches, materials, equipment, customer or client lists or information, or any other documents or property (including all reproductions of the aforementioned items) belonging to the Company or any of its Affiliates or ventures, regardless of whether such items were prepared by Executive.

7. **Non-Solicitation And Non-Competition:**

(a) For consideration provided under this Agreement, including, but not limited to the Company's agreement to provide Executive with Confidential Information (as defined in Section 5) regarding the Company and the Company's business, Executive agrees that while employed by the Company and for one year following a Covered Termination he shall not, without the prior written consent of the Company, directly or indirectly, (i) hire or induce, entice or solicit (or attempt to induce, entice or solicit) any employee of the Company or any of its Affiliates or ventures to leave the employment of the Company or any of its Affiliates or ventures or (ii) solicit or attempt to solicit the business of any customer or acquisition prospect of the Company or any of its Affiliates or ventures with whom Executive had any actual contact while employed at the Company.

(b) Additionally, for consideration provided under this Agreement, including, but not limited to the Company's agreement to provide Executive with Confidential Information regarding the Company and the Company's business, Executive agrees that while employed by the Company and for one year following a Covered Termination he will not, without the prior written consent of the Company, acting alone or in conjunction with others, either directly or indirectly, engage in any business that is in competition with the Company or accept employment with or render services to such a business as an officer, agent, employee, independent contractor or consultant, or otherwise engage in activities that are in competition with the Company.

(c) The restrictions contained in this Section 7 are limited to a 50-mile radius around any geographical area in which the Company engages (or has definite plans to engage) in operations or the marketing of its products or services at the time of a Covered Termination.

(d) Executive acknowledges that these restrictive covenants under this Agreement, for which Executive received valuable consideration from the Company as provided in this Agreement, including, but not limited to the Company's agreement to provide Executive with Confidential Information regarding the Company and the Company's business are ancillary to otherwise enforceable provisions of this Agreement that the consideration provided by the Company gives rise to the Company's interest in restraining Executive from competing and that the restrictive covenants are designed to enforce Executive's consideration or return promises under this Agreement. Additionally, Executive acknowledges that these restrictive covenants contain limitations as to time, geographical area, and scope of activity to be restrained that are reasonable and do not impose a greater restraint than is necessary to protect the goodwill or other legitimate business interests of the Company, including, but not limited to, the Company's need to protect its Confidential Information.

8. **Conflicts With Other Agreements:** In the event that Executive becomes entitled to benefits under a prior or subsequent agreement pertaining to Executive's employment by the Company or any Affiliate thereof (other than this Agreement) or the benefits to which Executive is entitled as a result of such employment and such benefits conflict with the terms of this Agreement, Executive will receive the greater and more favorable of each of the benefits provided under either this Agreement or such other agreement or benefits, on an individual benefit basis.

9. **Notices:** For purposes of this Agreement, notices and all other communications provided for herein shall be in writing and shall be deemed to have been duly given when personally delivered or when mailed by United States registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to Company:	CenterPoint Energy, Inc. 1111 Louisiana Houston, Texas 77002 Attention: President and Chief Executive Officer
If to Executive:	**[NAME]** **[ADDRESS]** **[CITY, STATE, ZIP]**

or to such other address as either party may furnish to the other in writing in accordance herewith, except that notices of changes of address shall be effective only upon receipt.

10. **Litigation Assistance:** Executive agrees to assist the Company with any litigation matters related to the Company or any of its subsidiaries or affiliates as may be reasonably requested by the Company's General Counsel following the date of Executive's Covered Termination. The Company shall reimburse Executive for any reasonable travel or other business expenses incurred in connection with providing such assistance and cooperation. Executive shall provide such services as an independent contractor and such services shall be limited solely to those matters with which Executive is suitably experienced and knowledgeable by reason of Executive's education, training, background and prior employment with the Company. The Company and Executive agree to work out reasonable accommodations for the provision of such assistance so that it does not unreasonably interfere with any of Executive's personal affairs, business endeavors or future employment. The foregoing notwithstanding, the Company and Executive agree that the services provided by Executive under this Section, if any, shall not exceed twenty percent (20%) of the average level of bona fide services performed by Executive (whether as an employee or an independent contractor of the Company) over the 36-month period (or the full period of services to the Company if Executive has been providing services to the Company for less than 36 months) immediately preceding his Covered Termination date.

11. **Prior Agreements/Modification:** This Agreement contains the entire agreement between the parties with respect to the subject matter hereof and supersedes all prior agreements or understandings, whether written or oral, between the parties with respect thereto. This Agreement may be amended only by an agreement in writing signed by the parties hereto; *provided*, *however*, that Executive's compensation may be increased at any time by the Company without in any way affecting any of the other terms and conditions of this Agreement which in all other respects shall remain in full force and effect. Notwithstanding the foregoing to the contrary, to the extent permitted under Code Section 409A and the regulations and guidance issued thereunder ("Section 409A"), the Company may amend the definition of a Change in Control under this Agreement to be compliant with the definition of a "change in control" under Code Section 409A, as the Company determines is appropriate in its sole discretion, without the consent of Executive. The provisions of this Agreement will be binding upon, and will inure to the benefit of, the respective heirs, legal representatives and successors of the parties hereto. Executive represents to the Company that he is not a party to any agreement or subject to any legal restriction that would prevent him from fulfilling his duties hereunder.

12. **Section 409A:** The Company and Executive mutually desire to avoid imposition of an excise tax under Section 409A. Accordingly, if any provision provided herein results in the imposition of an excise tax under the provisions of Section 409A, the parties agree to fully cooperate in good faith and take appropriate reasonable actions to amend and/or operate the Agreement to avoid any such imposition as Executive and the Company determine is appropriate to comply with Section 409A. Notwithstanding any provision of this Agreement to the contrary, the parties agree that any benefit or benefits under this Agreement that the Company determines are subject to the suspension period under Code Section 409A(a)(2)(B) shall not be paid or commence until a date following six months after Executive's Covered Termination date, or if earlier, Executive's death.

All reimbursements and in-kind benefits provided pursuant to this Agreement shall be made in accordance with Treasury Regulations Section 1.409A-3(i)(1)(iv) such that any reimbursements or in-kind benefits will be deemed payable at a specified time or on a fixed schedule relative to a permissible payment event. Specifically, (a) the amounts reimbursed and in-kind benefits under this Agreement, other than with respect to medical benefits provided under Section 2(d), during Executive's taxable year may not affect the amounts reimbursed or in-kind benefits provided in any other taxable year, (b) the reimbursement of an eligible expense shall be made on or before the last day of Executive's taxable year following the taxable year in which the expense was incurred, and (c) the right to reimbursement or an in-kind benefit is not subject to liquidation or exchange for another benefit.

13. **Applicable Law:** The validity, interpretation, construction and performance of this Agreement will be governed by and construed in accordance with the substantive laws of the State of Texas, including the Texas statute of limitations, but without giving effect to the principles of conflict of laws of such State.

14. **Severability:** If a court of competent jurisdiction determines that any provision of this Agreement is invalid or unenforceable, then the invalidity or unenforceability of that provision shall not affect the validity or enforceability of any other provision of this Agreement and all other provisions shall remain in full force and effect.

15. **Withholding of Taxes:** The Company may withhold from any benefits payable under this Agreement all federal, state, city or other taxes as may be required pursuant to any law or governmental regulation or ruling.

16. **No Employment Agreement:** Nothing in this Agreement shall give Executive any rights to (or impose any obligations for) continued employment by the Company or any Affiliate thereof or successor thereto, nor shall it give the Company any rights (or impose any obligations) with respect to continued performance of duties by Executive for the Company or any Affiliate thereof or successor thereto.

17. **No Assignment; Successors:** Executive's right to receive payments or benefits hereunder shall not be assignable or transferable, whether by pledge, creation or a security interest or otherwise, whether voluntary, involuntary, by operation of law or otherwise, other than a transfer by will or by the laws of descent or distribution, and in the event of any attempted assignment or transfer contrary to this Section 17, the Company shall have no liability

to pay any amount so attempted to be assigned or transferred. This Agreement shall inure to the benefit of and be enforceable by Executive's personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees and legatees.

This Agreement shall be binding upon and inure to the benefit of the Company, its successors and assigns (including, without limitation, any company into or with which the Company may merge or consolidate). The Company agrees that it will not effect the sale or other disposition of all or substantially all of its assets unless either (a) the person or entity acquiring such assets or a substantial portion thereof shall expressly assume by an instrument in writing all duties and obligations of the Company hereunder or (b) the Company shall provide, through the establishment of a separate reserve therefor, for the payment in full of all amounts which are or may reasonably be expected to become payable to Executive hereunder.

18. **Payment Obligations Absolute:** Except for the requirement of Executive to execute and return to the Company a Waiver and Release in accordance with Section 2, the Company's obligation to pay (or cause one of its Affiliates to pay) Executive the amounts and to make the arrangements provided herein shall be absolute and unconditional and shall not be affected by any circumstances, including, without limitation, any set-off, counter-claim, recoupment, defense or other right which the Company (including its Affiliates) may have against him or anyone else. All amounts payable by the Company (including its Affiliates hereunder) shall be paid without notice or demand. Executive shall not be obligated to seek other employment in mitigation of the amounts payable or arrangements made under any provision of this Agreement, and, subject to the restrictions in Section 7, the obtaining of any other employment shall in no event affect any reduction of the Company's obligations to make (or cause to be made) the payments and arrangements required to be made under this Agreement.

The Company will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place. As used in this Agreement, "Company" shall mean the Company as hereinbefore defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform this Agreement by operation of law, or otherwise. If a Business Combination is consummated that would have resulted in a Change in Control but for the satisfaction of the conditions specified in clauses (i), (ii), (iii) and (iv) of subsection (c) of the definition of "Change in Control" in Section 1 and if the Parent Corporation resulting from the Business Combination is other than the Company (hereinafter a "New Parent"), then, as a condition to consummation of this Business Combination, the New Parent shall be considered a successor for purposes of this paragraph.

19. **Number and Gender:** Wherever appropriate herein, words used in the singular shall include the plural and the plural shall include the singular. The masculine gender where appearing herein shall be deemed to include the feminine gender.

20. **Term:** The effective date of the Agreement is January 1, 2008 ("Effective Date"). The term of this Agreement shall commence on the Effective Date and shall end on December 31, 2008; *provided, however*, that on each January 1st thereafter, the term of this

Agreement shall automatically be extended for one additional year unless, prior to any such January 1st, the Board decides not to extend the term of this Agreement, in which event the term shall, without further action, expire, and this Agreement shall terminate, on the December 31st of the year in which the Board makes such decision. The foregoing to the contrary notwithstanding, (a) if, prior to a Change in Control, Executive ceases for any reason other than due to a Covered Termination to be an employee of the Company, then the term shall, without further action, expire, and this Agreement shall terminate, as of such termination date; and (b) upon the Company entering into a binding agreement to effect a Change in Control, if the Agreement has not expired prior to such date, the term of this Agreement shall automatically be extended until the end of the two-year period commencing as of the date of the Change in Control; *provided, however*, that, the foregoing clause (b) notwithstanding, if the board of directors of the parties to such binding agreement agree, as evidenced by their resolutions, not to consummate the Change in Control, the term of this Agreement shall be determined as otherwise provided in this Section 20 without regard to clause (b).

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed and delivered as of the date first above written, but effective as of the Effective Date.

CENTERPOINT ENERGY, INC.

By: ______________________________
David M. McClanahan
President and Chief Executive Officer

EXECUTIVE

____
[NAME]

Waiver And Release

In exchange for the payment to me of the Severance Benefits described in Section 2 of the Change in Control Agreement between CenterPoint Energy, Inc., and me effective as of January 1, 2008 (the "Agreement"), which I understand is incorporated herein by reference, and of other remuneration and consideration provided for in the Agreement (the "Severance Benefits"), which is in addition to any remuneration or benefits to which I am already entitled, I agree to waive all of my claims against and release (i) CenterPoint Energy, Inc. and its predecessors, successors and assigns (collectively referred to as the "Company"), (ii) all of the affiliates (including, but not limited to, CenterPoint Energy Services Company, CenterPoint Energy Southern Gas Operations, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas Operations, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Oklahoma Gas, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas, CenterPoint Energy Houston Gas, CenterPoint Energy Pipeline Services, Inc., CenterPoint Energy Services, Inc., CenterPoint Energy Field Services, Inc., CenterPoint Energy Gas Transmission Company, CenterPoint Energy Mississippi River Transmission Corporation, and all wholly or partially owned subsidiaries) of the Company and their predecessors, successors and assigns (collectively referred to as the "Company Affiliates") and (iii) the Company's and Company Affiliates' directors and officers, employees and agents, insurers, employee benefit plans and the fiduciaries and agents of the foregoing (collectively, with the Company and Company Affiliates, referred to as the "Corporate Group") from any and all claims, demands, actions, liabilities and damages arising out of or relating in any way to my employment with or separation from the Company or the Company Affiliates. All payments under the Agreement are voluntary and are not required by any legal obligation other than the Agreement itself.

I understand that signing this Waiver and Release is an important legal act. I acknowledge that I have been advised in writing to consult an attorney before signing this Waiver and Release. I understand that, in order to be eligible for Severance Benefits under the Agreement, I must sign and return (to Carol Helliker, Vice President, Corporate Compliance Officer and Associate General Counsel, Legal Department, at CenterPoint Energy Tower, 46th Floor, 1111 Louisiana, Houston, Texas 77002) this Waiver and Release within 50 days following the date of my termination of employment. I acknowledge that I have been given at least 45 days to consider whether to execute this Waiver and Release.

In exchange for the payment to me of Severance Benefits pursuant to the Agreement, which is in addition to any remuneration or benefits to which I am already entitled, (1) I agree not to sue in any local, state and/or federal court or to file a grievance regarding or relating in any way to my employment with or separation from the Company or the Company Affiliates, and (2) I knowingly and voluntarily waive all claims and release the Corporate Group from any and all claims, demands, actions, liabilities, and damages, whether known or unknown, arising out of or relating in any way to my employment with or separation from the Company or the Company Affiliates, except to the extent that my rights are vested under the terms of employee benefit plans sponsored by the Company or the Company Affiliates and except with respect to such rights or claims as may arise after the date this Waiver and Release is executed. This Waiver and Release includes, but is not limited to, claims and causes of action under: Title

VII of the Civil Rights Act of 1964, as amended ("Title VII"); the Age Discrimination in Employment Act of 1967, as amended, including the Older Workers Benefit Protection Act of 1990 ("ADEA"); the Civil Rights Act of 1866, as amended; the Civil Rights Act of 1991; the Americans with Disabilities Act of 1990 ("ADA"); the Energy Reorganization Act, as amended, 42 U.S.C. § 5851; the Workers Adjustment and Retraining Notification Act of 1988; the Pregnancy Discrimination Act of 1978; the Employee Retirement Income Security Act of 1974, as amended; the Family and Medical Leave Act of 1993; the Fair Labor Standards Act; the Occupational Safety and Health Act; claims in connection with workers' compensation or "whistle blower" statutes; and/or contract, tort, defamation, slander, wrongful termination or any other state or federal regulatory, statutory or common law. Further, I expressly represent that no promise or agreement which is not expressed in the Agreement or this Waiver and Release has been made to me in executing this Waiver and Release, and that I am relying on my own judgment in executing this Waiver and Release, and that I am not relying on any statement or representation of any member of the Corporate Group or any of their agents. I agree that this Waiver and Release is valid, fair, adequate and reasonable, is with my full knowledge and consent, was not procured through fraud, duress or mistake and has not had the effect of misleading, misinforming or failing to inform me. I acknowledge and agree that the Company will withhold any taxes required by federal or state law from the Severance Benefits otherwise payable to me and that the Severance Benefits otherwise payable to me shall be reduced by any monies owed by me to the Company (or a Company Affiliate), including, but not limited to, any overpayments made to me by the Company (or a Company Affiliate) and the balance of any loan by the Company (or a Company Affiliate) to me that is outstanding at the time that the Severance Benefits are paid.

I acknowledge that payment of Severance Benefits pursuant to the Agreement is not an admission by any member of the Corporate Group that they engaged in any wrongful or unlawful act or that any member of the Corporate Group violated any federal or state law or regulation. I understand that nothing in this Waiver and Release is intended to prohibit, restrict or otherwise discourage any individual from engaging in activity protected under 42 U.S.C. § 5851, 10 C.F.R. § 50.7 or the Sarbanes-Oxley Act of 2002, including, but not limited to, providing information to the Nuclear Regulatory Commission ("NRC") or to any member of the Corporate Group regarding nuclear safety or quality concerns, potential violations or other matters within the NRC's jurisdiction. I acknowledge that no member of the Corporate Group has promised me continued employment or represented to me that I will be rehired in the future. I acknowledge that my employer and I contemplate an unequivocal, complete and final dissolution of my employment relationship. I acknowledge that this Waiver and Release does not create any right on my part to be rehired by any member of the Corporate Group and I hereby waive any right to future employment by any member of the Corporate Group.

I have returned or I agree that I will return immediately, and maintain in strictest confidence and will not use in any way, any confidential and proprietary business information or other nonpublic information or documents relating to the business and affairs of the Corporate Group. For the purposes of this Waiver and Release, "confidential and proprietary business information" shall mean any information concerning any member of the Corporate Group or their business which I learn or develop during my employment and which is not generally known or available outside of the Corporate Group. Such information, without limitation, includes information, written or otherwise, regarding any member of the Corporate Group's earnings, expenses, material sources, equipment sources, customers and prospective customers, business plans, strategies, practices and procedures, prospective and executed contracts and other business arrangements. I acknowledge and agree that all records, papers, reports, computer programs, strategies, documents (including, without limitation, memoranda, notes, files and correspondence), opinions, evaluations, inventions, ideas, technical data, products, services, processes, procedures, and interpretations that are or have been produced by me or any employee, officer, director, agent, contractor, or representative of any member of the Corporate Group, whether provided in written or printed form, or orally, all comprise confidential and proprietary business information. I agree that for a period of one year following my termination with the Corporate Group that I will not: (a) solicit, encourage or take any action that is intended, directly or indirectly, to induce any other employee of the Corporate Group to terminate employment with the Corporate Group; (b) interfere in any manner with the contractual or employment relationship between the Corporate Group and any other employee of the Corporate Group; and (c) use any confidential information to directly, or indirectly, solicit any customer of the Corporate Group. I understand and agree that in the event of any breach of the provisions of this paragraph, or threatened breach, by me, any member of the Corporate Group may, in their discretion, discontinue any or all payments provided for in the Agreement and recover any and all payments already made and any member of the Corporate Group shall be entitled to apply to a court of competent jurisdiction for such relief by way of specific performance, restraining order, injunction or otherwise as may be appropriate to ensure compliance with these provisions. Should I be contacted or served with legal process seeking to compel me to disclose any such information, I agree to notify the General Counsel of the Company immediately, in order that the Corporate Group may seek to resist such process if they so choose. If I am called upon to serve as a witness or consultant in or with respect to any potential litigation, litigation, arbitration, or regulatory proceeding, I agree to cooperate with the Corporate Group to the full extent permitted by law, and the Corporate Group agrees that any such call shall be with reasonable notice, shall not unnecessarily interfere with my later employment, and shall provide for payment for my time and costs expended in such matters.

Should any of the provisions set forth in this Waiver and Release be determined to be invalid by a court, agency or other tribunal of competent jurisdiction, it is agreed that such determination shall not affect the enforceability of other provisions of this Waiver and Release. I acknowledge that this Waiver and Release and the Agreement set forth the entire understanding and agreement between me and the Company or any other member of the Corporate Group concerning the subject matter of this Waiver and Release and supersede any prior or contemporaneous oral and/or written agreements or representations, if any, between me and the Company or any other member of the Corporate Group. I understand that for a period of 7 calendar days following the date I sign this Waiver and Release (which date must within 50 days following the date of my termination of employment), I may revoke my acceptance of the offer by delivering a written statement to the Vice President, Corporate Compliance Officer and Associate General Counsel (or the person designated by the Vice President, Corporate Compliance Officer and Associate General Counsel) by hand or by registered-mail, in which case the Waiver and Release will not become effective. In the event I revoke my acceptance of this offer, I shall not be entitled to any Severance Benefits under the Agreement. I understand that failure to revoke my acceptance of the offer within 7 calendar days following the date I sign this Waiver and Release will result in this Waiver and Release being permanent and irrevocable.

I acknowledge that I have read this Waiver and Release, have had an opportunity to ask questions and have it explained to me and that I understand that this Waiver and Release will have the effect of knowingly and voluntarily waiving any action I might pursue, including breach of contract, personal injury, retaliation, discrimination on the basis of race, age, sex, national origin, religion, veterans status, or disability and any other claims arising prior to the date of this Waiver and Release. By execution of this document, I do not waive or release or otherwise relinquish any legal rights I may have which are attributable to or arise out of acts, omissions, or events of any member of the Corporate Group which occur after the date of the execution of this Waiver and Release.

Executive's Printed Name	Corporate Group's Representative
Executive's Signature	Corporate Group's Execution Date
Executive's Signature Date	Executive's Social Security Number

Exhibit 12

CENTERPOINT ENERGY, INCORPORATED AND SUBSIDIARIES

COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Millions of Dollars)

	2003	2004	2005	2006	2007(1)
Income from continuing operations	$ 409	$ 205	$ 225	$ 432	$ 399
Income taxes for continuing operations	205	139	153	62	195
Capitalized interest	(4)	(4)	(4)	(10)	(22)
	610	340	374	484	572
Fixed charges, as defined:					
Interest	713	777	710	600	626
Capitalized interest	4	4	4	10	22
Distribution on trust preferred securities	28	—	—	—	—
Interest component of rentals charged to operating expense	11	11	12	19	16
Total fixed charges	756	792	726	629	664
Earnings, as defined	$ 1,366	$ 1,132	$ 1,100	$ 1,113	$ 1,236
Ratio of earnings to fixed charges	1.81	1.43	1.51	1.77	1.86

(1) Excluded from the computation of fixed charges is interest income of $4 million in 2007, which is included in income tax expense.

EXHIBIT 21

SIGNIFICANT SUBSIDIARIES OF CENTERPOINT ENERGY, INC.

The following subsidiaries are deemed “significant subsidiaries” pursuant to Item 601(b) (21) of Regulation S-K:

Utility Holding, LLC, a Delaware limited liability company and a direct wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Investment Management, Inc., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Resources Corp., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Houston Electric, LLC, a Texas limited liability company and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Services, Inc., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Gas Transmission Company, a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Field Services, Inc., a Delaware corporation and an indirect wholly owned subsidiary of CenterPoint Energy, Inc.

(1) Pursuant to Item 601(b) (21) of Regulation S-K, registrant has omitted the names of subsidiaries, which considered in the aggregate as a single subsidiary, would not constitute a “significant subsidiary” (as defined under Rule 1-02(w) of Regulation S-X) as of December 31, 2007.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-120306, 333-116246, 333-114543 on Form S-3; Registration Statement No. 333-105773 on Form S-8; Post-Effective Amendment No. 1 to Registration Statement No. 333-33303-99 on Form S-3; Post Effective Amendment No. 1 to Registration Statement Nos. 333-32413-99, 333-49333-99, 333-38188-99, 333-60260-99, 333-98271-99, 333-101202 and 333-115976 on Form S-8; and Post-Effective Amendment No. 5 to Registration Statement No. 333-11329-99 on Form S-8 of our reports dated February 28, 2008, relating to i) the consolidated financial statements of CenterPoint Energy, Inc. and subsidiaries (the “Company”) (such report expresses an unqualified opinion and includes an explanatory paragraph regarding the Company’s adoption of new accounting standards related to defined benefit pension and other postretirement plans in 2006 and conditional asset retirement obligations in 2005), ii) the consolidated financials statement schedules, and iii) the effectiveness of the Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of CenterPoint Energy, Inc. for the year ended December 31, 2007.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2008

Exhibit 31.1

CERTIFICATIONS

I, David M. McClanahan, certify that:

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

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 13(a)-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: February 28, 2008

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

Exhibit 31.2

CERTIFICATIONS

I, Gary L. Whitlock, certify that:

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

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 13(a)-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: February 28, 2008

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

Exhibit 32.1

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

In connection with the Annual Report of CenterPoint Energy, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2007 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, David M. McClanahan, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ David M. McClanahan

David M. McClanahan
President and Chief Executive Officer
February 28, 2008

Exhibit 32.2

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

In connection with the Annual Report of CenterPoint Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2007 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Gary L. Whitlock, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ Gary L. Whitlock

Gary L. Whitlock
Executive Vice President and Chief Financial Officer
February 28, 2008