CENTERPOINT ENERGY INC
Form 10-Q
August 06, 2008

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

FORM 10-Q

(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2008

OR

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

FOR THE TRANSITION PERIOD FROM ______________ TO _______________.

Commission file number 1-31447

CENTERPOINT ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

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

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

Large accelerated filer þ	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 £ No R

As of July 31, 2008, CenterPoint Energy, Inc. had 341,823,692 shares of common stock outstanding, excluding 166 shares held as treasury stock.

CENTERPOINT ENERGY, INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2008

TABLE OF CONTENTS

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 "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.

The following are some of the factors that could cause actual results to differ materially from those expressed or implied in forward-looking statements:

- the resolution of the true-up proceedings, 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 or re-regulation of our businesses, 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 rates 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 in “Risk Factors” in Item 1A of Part I of our Annual Report on Form 10-K for the year ended December 31, 2007, which is incorporated herein by reference, and other reports we file from time to time with the Securities and Exchange Commission.

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. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED INCOME
(Millions of Dollars, Except Per Share Amounts)
(Unaudited)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Ended June 30, 2008
Revenues	$ 2,033	$ 2,670	$ 5,139	$ 6,033
Expenses:				
Natural gas	1,208	1,750	3,358	4,143
Operation and maintenance	330	342	682	707
Depreciation and amortization	160	188	305	346
Taxes other than income taxes	93	93	199	204
Total	1,791	2,373	4,544	5,400
Operating Income	242	297	595	633
Other Income (Expense):				
Gain (loss) on Time Warner investment	28	17	(16)	(37)
Gain (loss) on indexed debt securities	(27)	(17)	14	33
Interest and other finance charges	(119)	(113)	(242)	(228)
Interest on transition bonds	(32)	(35)	(63)	(68)
Other, net	6	14	12	27
Total	(144)	(134)	(295)	(273)
Income Before Income Taxes	98	163	300	360
Income tax expense	(28)	(62)	(100)	(136)
Net Income	$ 70	$ 101	$ 200	$ 224
Basic Earnings Per Share	$ 0.22	$ 0.30	$ 0.62	$ 0.68
Diluted Earnings Per Share	$ 0.20	$ 0.30	$ 0.58	$ 0.66

See Notes to the Company’s Interim Condensed Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)
(Unaudited)

ASSETS

	December 31, 2007	June 30, 2008
Current Assets:		
Cash and cash equivalents	$ 129	$ 150
Investment in Time Warner common stock	357	320
Accounts receivable, net	910	991
Accrued unbilled revenues	558	281
Natural gas inventory	395	321
Materials and supplies	95	104
Non-trading derivative assets	38	102
Prepaid expenses and other current assets	306	329
Total current assets	2,788	2,598
Property, Plant and Equipment:		
Property, plant and equipment	13,250	13,500
Less accumulated depreciation and amortization	3,510	3,592
Property, plant and equipment, net	9,740	9,908
Other Assets:		
Goodwill	1,696	1,696
Regulatory assets	2,993	2,847
Non-trading derivative assets	11	96
Notes receivable from unconsolidated affiliates	148	244
Other	496	687
Total other assets	5,344	5,570
Total Assets	$ 17,872	$ 18,076

See Notes to the Company’s Interim Condensed Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS – (continued)
(Millions of Dollars)
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	December 31, 2007	June 30, 2008
Current Liabilities:		
Short-term borrowings	$ 232	$ 200
Current portion of transition bond long-term debt	159	186
Current portion of other long-term debt	1,156	123
Indexed debt securities derivative	261	228
Accounts payable	726	728
Taxes accrued	316	259
Interest accrued	170	177
Non-trading derivative liabilities	61	30
Accumulated deferred income taxes, net	350	336
Other	360	546
Total current liabilities	3,791	2,813
Other Liabilities:		
Accumulated deferred income taxes, net	2,235	2,227
Unamortized investment tax credits	31	28
Non-trading derivative liabilities	14	9
Benefit obligations	499	485
Regulatory liabilities	828	806
Other	300	389
Total other liabilities	3,907	3,944
Long-term Debt:		
Transition bonds	2,101	2,485
Other	6,263	6,869

Total long-term debt		8,364		9,354
Commitments and Contingencies (Note 10)				
Shareholders' Equity:				
Common stock (322,718,785 shares and 341,778,004 shares outstanding at December 31, 2007 and June 30, 2008, respectively)		3		3
Additional paid-in capital		3,023		3,078
Accumulated deficit		(1,172)		(1,068)
Accumulated other comprehensive loss		(44)		(48)
Total shareholders' equity		1,810		1,965
Total Liabilities and Shareholders' Equity	$	17,872	$	18,076

See Notes to the Company's Interim Condensed Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Millions of Dollars)
(Unaudited)

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2008
Cash Flows from Operating Activities:		
Net income	$ 200	$ 224
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	305	346
Amortization of deferred financing costs	33	14
Deferred income taxes	12	12
Unrealized loss on Time Warner investment	16	37
Unrealized gain on indexed debt securities	(14)	(33)
Write- down of natural gas inventory	6	—
Changes in other assets and liabilities:		
Accounts receivable and unbilled revenues, net	404	196
Inventory	12	65
Accounts payable	(294)	20
Fuel cost over (under) recovery	(39)	3
Non-trading derivatives, net	17	21
Margin deposits, net	80	95
Interest and taxes accrued	(149)	(51)
Net regulatory assets and liabilities	31	14
Other current assets	(43)	(93)
Other current liabilities	(77)	78
Other assets	(17)	(29)
Other liabilities	(66)	(53)
Other, net	10	2
Net cash provided by operating activities	427	868
Cash Flows from Investing Activities:		
Capital expenditures	(664)	(419)
Decrease (increase) in restricted cash of transition bond companies	1	(7)
Increase in notes receivable from unconsolidated affiliates	—	(96)
Investment in unconsolidated affiliates	(34)	(162)
Other, net	(12)	(16)
Net cash used in investing activities	(709)	(700)
Cash Flows from Financing Activities:		
Increase (decrease) in short-term borrowings, net	38	(32)
Long-term revolving credit facilities, net	—	61
Proceeds from commercial paper, net	353	130
Proceeds from long-term debt	400	1,088
Payments of long-term debt	(434)	(1,291)
Debt issuance costs	(4)	(10)

Payment of common stock dividends		(109)		(120)
Proceeds from issuance of common stock, net		19		26
Other		4		1
Net cash provided by (used in) financing activities		267		(147)
Net Increase (Decrease) in Cash and Cash Equivalents		(15)		21
Cash and Cash Equivalents at Beginning of Period		127		129
Cash and Cash Equivalents at End of Period	$	112	$	150
Supplemental Disclosure of Cash Flow Information:				
Cash Payments:				
Interest, net of capitalized interest	$	285	$	287
Income taxes		178		142

See Notes to the Company's Interim Condensed Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

General. Included in this Quarterly Report on Form 10-Q (Form 10-Q) of CenterPoint Energy, Inc. are the condensed consolidated interim financial statements and notes (Interim Condensed Financial Statements) of CenterPoint Energy, Inc. and its subsidiaries (collectively, CenterPoint Energy, or the Company). The Interim Condensed Financial Statements are unaudited, omit certain financial statement disclosures and should be read with the Annual Report on Form 10-K of CenterPoint Energy for the year ended December 31, 2007 (CenterPoint Energy Form 10-K).

Background. CenterPoint Energy, Inc. 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 June 30, 2008, 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.

Basis of Presentation. The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) 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.

The Company's Interim Condensed Financial Statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position, results of operations and cash flows for the respective periods. Amounts reported in the Company's Condensed Statements of Consolidated Income are not necessarily indicative of amounts expected for a full-year period due to the effects of, among other things, (a) seasonal fluctuations in demand for energy and energy services, (b) changes in energy commodity prices, (c) timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests.

For a description of the Company's reportable business segments, reference is made to Note 13.

(2) New Accounting Pronouncements

In April 2007, the Financial Accounting Standards Board (FASB) issued Staff Position No. FIN 39-1, "Amendment of FASB Interpretation No. 39," (FIN 39-1) which permits companies that enter into master netting arrangements to offset cash collateral receivables or payables with net derivative positions under certain circumstances. The Company adopted FIN 39-1 effective January 1, 2008 and began netting cash collateral receivables and payables and also its derivative assets and liabilities with the same counterparty subject to master netting agreements.

In February 2007, the FASB issued Statement of Financial Accounting Standard (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 applicable 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 or cash flows.

Effective January 1, 2008, the Company adopted SFAS No. 157, “Fair Value Measurements” (SFAS No. 157), which requires additional disclosures about the Company’s financial assets and liabilities that are measured at fair value. FASB Staff Position No. FAS 157-2 delays the effective date for SFAS No. 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, to fiscal years, and interim periods within those fiscal years, beginning after November 15, 2008. Beginning in January 2008, assets and liabilities recorded at fair value in the Condensed Consolidated Balance Sheet are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined in SFAS No. 157 and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities, are as follows:

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

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

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls has been determined based on the lowest level input that is significant to the fair value measurement in its entirety. The Company’s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment, and considers factors specific to the asset. Generally, assets and liabilities carried at fair value and included in this category are financial derivatives.

The following table presents information about the Company's assets and liabilities (including derivatives that are presented net) measured at fair value on a recurring basis as of June 30, 2008, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance as of June 30, 2008
			(in millions)		
Assets					
Corporate equities	$ 322	$ —	$ —	$ —	$ 322
Investments	51	—	—	—	51
Derivative assets	62	266	14	(144)	198
Total assets	$ 435	$ 266	$ 14	$ (144)	$ 571
Liabilities					
Indexed debt securities derivative	$ —	$ 228	$ —	$ —	$ 228
Derivative liabilities	70	42	8	(81)	39
Total liabilities	$ 70	$ 270	$ 8	$ (81)	$ 267

(1) Amounts represent the impact of legally enforceable master netting agreements that allow the Company to settle positive and negative positions and also cash collateral held or placed with the same counterparties.

The following table presents additional information about assets or liabilities, including derivatives that are measured at fair value on a recurring basis for which the Company has utilized Level 3 inputs to determine fair value, for the three months ended June 30, 2008:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Derivative assets and liabilities, net (in millions)
Beginning balance as of April 1, 2008	$ 2
Total gains or losses (realized and unrealized):	
Included in earnings	3
Purchases, sales, other settlements, net	1
Ending balance as of June 30, 2008	$ 6
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ 3

The following table presents additional information about assets or liabilities, including derivatives that are measured at fair value on a recurring basis for which the Company has utilized Level 3 inputs to determine fair value, for the six months ended June 30, 2008:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Derivative assets and liabilities, net (in millions)
Beginning balance as of January 1, 2008	$ (3)
Total gains or losses (realized and unrealized):	
Included in earnings	9
Ending balance as of June 30, 2008	$ 6
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ 4

7

In May 2008, the FASB issued FASB Staff Position ("FSP") No. APB 14-1 "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)", which will change the accounting treatment for convertible securities that the issuer may settle fully or partially in cash. Under the final FSP, cash settled convertible securities will be separated into their debt and equity components. The value assigned to the debt component will be the estimated fair value, as of the issuance date, of a similar debt instrument without the conversion feature, and the difference between the proceeds for the convertible debt and the amount reflected as a debt liability will be recorded as additional paid-in capital. As a result, the debt will be recorded at a discount reflecting its below market coupon interest rate. The debt will subsequently be accreted to its par value over its expected life, with the rate of interest that reflects the market rate at issuance being reflected on the income statement. The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. The Company currently has no convertible debt that is within the scope of this FSP, but this FSP will be applied retrospectively and will affect net income for prior periods and the consolidated balance sheets when the Company had contingently convertible debt outstanding. The Company is currently evaluating the effect of these retrospective adjustments, but does not expect the retrospective adjustments to be material.

In May 2008, the FASB issued SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles” (SFAS No. 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP. The Company plans to adopt SFAS No. 162 when it becomes effective. The adoption of SFAS No. 162 will not have an impact on the Company’s consolidated financial position or results of operations.

(3) Employee Benefit Plans

The Company’s net periodic cost includes the following components relating to pension and postretirement benefits:

	Three Months Ended June 30,			
	2007		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)			
Service cost	$ 9	$ 1	$ 7	$ 1
Interest cost	25	6	26	7
Expected return on plan assets	(37)	(3)	(37)	(3)
Amortization of prior service cost	(2)	1	(2)	1
Amortization of net loss	9	—	6	—
Amortization of transition obligation	—	1	—	1
Net periodic cost	$ 4	$ 6	$ —	$ 7

	Six Months Ended June 30,			
	2007		2008	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)			
Service cost	$ 18	$ 1	$ 15	$ 1
Interest cost	50	13	51	14
Expected return on plan assets	(74)	(6)	(74)	(6)
Amortization of prior service cost	(4)	2	(4)	2

Amortization of net loss	18	—	12	—
Amortization of transition obligation	—	3	—	3
Net periodic cost	$ 8	$ 13	$ —	$ 14

The Company expects to contribute approximately $8 million to its pension plans in 2008, of which $2 million and $4 million, respectively, was contributed during the three and six months ended June 30, 2008.

The Company expects to contribute approximately $21 million to its postretirement benefits plan in 2008, of which $6 million and $12 million, respectively, was contributed during the three and six months ended June 30, 2008.

(4) Regulatory Matters

(a) Recovery of True-up Balance

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 certain other adjustments.

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 as requested by the Texas Utility Commission; and
- affirmed the district court's judgment in all other respects.

In April 2008, the court of appeals denied all motions for rehearing and reissued substantially the same opinion as it had rendered in December 2007.

In June 2008, CenterPoint Houston petitioned the Texas Supreme Court for review of the court of appeals decision. In its petition, CenterPoint Houston seeks reversal of the parts of the court of appeals decision that (i) denied recovery of EMCs paid to RRI, (ii) denied recovery of the capacity auction true up amounts allowed by the district court, (iii) affirmed the Texas Utility Commission's rulings that denied recovery of approximately $378 million related to depreciation and (iv) affirmed the Texas Utility Commission's refusal to permit CenterPoint Houston to utilize the partial stock valuation methodology for determining the market value of its former generation assets. Two other petitions for review were filed with the Texas Supreme Court by other parties to the appeal. In those petitions parties contend (i) that the Texas Utility Commission was without authority to fashion the methodology it used for valuing the former generation assets after it had determined that CenterPoint Houston could not use the partial stock valuation method, (ii) that in fashioning the method it used for valuing the former generating assets, the Texas Utility Commission deprived parties of their due process rights and an opportunity to be heard, (iii) that the net book value of the generating assets should have been adjusted downward due to the impact of a purchase option that had been granted to RRI, (iv) that CenterPoint Houston should not have been permitted to recover construction work in progress balances without proving those amounts in the manner required by law and (v) that the Texas Utility Commission was without authority to award interest on the capacity auction true up award.

Review by the Texas Supreme Court of the court of appeals decision is at the discretion of the court. There is no prescribed time in which the Texas Supreme Court must determine whether to grant review or, if review is granted, for a decision by that 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 appeal to the Texas Supreme Court, the Company can provide no assurance as to the ultimate court rulings on the issues to be considered in the appeal 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 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 (pre-tax) 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, the IRS subsequently withdrew those proposed normalization regulations and in March 2008 adopted final regulations that would not permit utilities like CenterPoint Houston to pass the tax benefits back to customers without creating normalization violations. In addition, the Company received a Private Letter Ruling (PLR) from the IRS in August 2007, prior to adoption of the final regulations, that confirmed that the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations with respect to the ADITC and EDFIT.

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. In its opinion, the court of appeals ordered that this issue be remanded to the Texas Utility Commission, as that commission requested. No party, in the petitions for review filed with the Texas Supreme Court, has challenged that order by the court of appeals, though the Texas Supreme Court, if it grants review, will have authority to consider all aspects of the rulings above, not just those challenged specifically by the appellants. 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. The return on the CTC portion of the true-up balance was included in CenterPoint Houston's tariff-based revenues beginning September 13, 2005. Effective August 1, 2006, the interest rate on the unrecovered balance of the CTC was reduced from 11.075% to 8.06% pursuant to a revised rule adopted by the Texas Utility Commission in June 2006.

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 revised rule discussed above. 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 appealed the district court's judgment to the Texas Third Court of Appeals, and in July 2008, the court of appeals reversed the district court's judgment in all respects and affirmed the Texas Utility Commission's order. The appellants may seek rehearing from the court of appeals and further review from the Texas Supreme Court. 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.

During the three months ended June 30, 2007 and 2008, CenterPoint Houston recognized approximately $10 million and $-0-, respectively, in operating income from the CTC, which was terminated in February 2008 when the transition bonds described below were issued. Additionally, during the three months ended June 30, 2007 and 2008, CenterPoint Houston recognized approximately $3 million and $2 million, respectively, of the allowed equity return not previously recorded.

During the six months ended June 30, 2007 and 2008, CenterPoint Houston recognized approximately $21 million and $5 million, respectively, in operating income from the CTC, which was terminated in February 2008 when the transition bonds described below were issued. Additionally, during the six months ended June 30, 2007 and 2008, CenterPoint Houston recognized approximately $6 million and $4 million, respectively, of the allowed equity return not previously recorded.

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, adjusted to refund certain unspent environmental retrofit costs and to recover the amount of the final fuel reconciliation settlement. 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, pursuant to the financing order, a new special purpose subsidiary of CenterPoint Houston issued approximately $488 million of 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. Contemporaneously with the issuance of those bonds, the CTC was terminated and a transition charge was implemented.

As of June 30, 2008, the Company had not recorded an allowed equity return of $214 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates.

(b) Rate Cases

Texas. In March 2008, CERC's natural gas distribution business (Gas Operations) filed a request to change its rates with the Railroad Commission of Texas (Railroad Commission) and the 47 cities in its Texas Coast service territory, an area consisting of approximately 230,000 customers in cities and communities on the outskirts of Houston. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Texas Coast service territory. Of the 47 cities, nine of those cities are represented by the Texas Coast Utilities Coalition (TCUC) and 15 cities are represented by the Gulf Coast Coalition of Cities (GCCC). The TCUC cities denied the rate change request and Gas Operations appealed the denial of rates to the Railroad Commission. The hearing on this issue is scheduled to begin in August 2008, with a final decision due no later than October 2008. In July 2008, Gas Operations reached a settlement agreement with the GCCC. The settlement agreement, if implemented across the entire Texas Coast service territory, would allow Gas Operations an additional $3.4 million in annual revenue and provides for an annual rate adjustment mechanism to reflect changes in operating expenses and revenues as well as changes in capital investment and associated changes in revenue-related taxes. By virtue of an agreement with the Texas Coast cities that have already implemented Gas Operations' rate request, the settled rates will apply to all cities in the Texas Coast service territory except the nine TCUC cities and the environs whose rates will be established by the Railroad Commission. However, if the Railroad Commission approves lower rates than the settled rates, rates in the entire Texas Coast service territory would be conformed to the lower rates.

Minnesota. In November 2006, the Minnesota Public Utilities Commission (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, and in May 2008 that court ruled that the MPUC had been arbitrary and capricious in denying Gas Operations a waiver. The court ordered the case remanded to the MPUC for reconsideration under the same principles the MPUC had applied in previously granted waiver requests. The MPUC sought further review of the court of appeals decision from the Minnesota Supreme Court, and in July 2008, the Minnesota Supreme Court agreed to review the decision. 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 has entered into certain derivative instruments that qualify as cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (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 each of the three and six months ended June 30, 2007 and 2008, hedge ineffectiveness resulted in a gain or loss of less than $1 million 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. 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 June 30, 2008, the Company expects $2 million 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 less than one year. The Company's policy is not to exceed ten years in hedging its exposure.

Hedging of Future Debt Issuances. In May 2008, the Company settled its treasury rate lock derivative instruments (treasury rate locks) for a payment of $7 million. The treasury rate locks, which were to expire in June 2008, had an aggregate notional amount of $300 million and a weighted-average locked U.S. treasury rate on ten-year debt of 4.05%. These treasury rate locks were executed to hedge the ten-year U.S. treasury rate expected to be used in pricing the $300 million of fixed-rate debt the Company planned to issue in 2008, because changes in the U.S treasury rate would cause variability in the Company's forecasted interest payments. These treasury rate locks qualified as cash flow hedges under SFAS No. 133. The $7 million loss recognized upon settlement of the treasury rate locks was recorded as a component of accumulated other comprehensive loss and will be recognized as a component of interest expense over the ten-year life of the related $300 million senior notes issued in May 2008. Amortization of amounts deferred in accumulated other comprehensive loss for the three and six months ended June 30, 2008 was less than $1 million. During the three months and six months ended June 30, 2008, the Company recognized a gain of $9 million and a loss of $5 million, respectively, for these treasury rate locks in accumulated other comprehensive loss. Ineffectiveness for the treasury rate locks was not material during the three and six months ended June 30, 2008.

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 three months ended June 30, 2007, the Company recorded increased natural gas expense from unrealized net losses of $6 million. During the three months ended June 30, 2008, the Company recorded increased revenues from unrealized net gains of $6 million and increased natural gas expense from unrealized net losses of $16 million, a net unrealized loss of $10 million. During the six months ended June 30, 2007, the Company recorded increased natural gas expense from unrealized net losses of $14 million. During the six months ended June 30, 2008, the Company recorded decreased revenues from unrealized net losses of $15 million and increased natural gas expense from unrealized net losses of $17 million, a net unrealized loss of $32 million.

Weather Derivatives. The Company has weather normalization or other rate mechanisms that mitigate the impact of weather in Arkansas, Louisiana and Oklahoma. 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 were based on ten-year normal weather and provided for a maximum payment by either party of $18 million. During the three and six months ended June 30, 2008, the Company recognized losses of $2 million and $13 million, respectively, related to these swaps. This was offset in part by increased revenues due to colder than normal weather. These weather derivative losses are included in revenues in the Condensed Statements of Consolidated Income.

In July 2008, 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 2008/2009 winter heating season. The swaps are based on ten-year normal weather and provide for a maximum payment by either party of $11 million.

(6) Goodwill

Goodwill by reportable business segment as of both December 31, 2007 and June 30, 2008 is as follows (in millions):

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

(7) Comprehensive Income

The following table summarizes the components of total comprehensive income (net of tax):

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2007		2008		2007		2008	
	(in millions)							
Net income	$	70	$	101	$	200	$	224
Other comprehensive income (loss):								
Adjustment to pension and other postretirement plans (net of tax of $1, $-0-, $3 and $1)		2		1		4		3
Net deferred gain (loss) from cash flow hedges (net of tax of $4, $3, $4 and $1)		5		6		5		(3)
Reclassification of deferred loss (gain) from cash flow hedges realized in net income (net of tax of $3, $-0-, $12 and $2)		5		—		(17)		(4)
Total		12		7		(8)		(4)
Comprehensive income	$	82	$	108	$	192	$	220

The following table summarizes the components of accumulated other comprehensive loss:

	December 31, 2007		June 30, 2008	
	(in millions)			
SFAS No. 158 incremental effect	$	(48)	$	(45)
Net deferred gain (loss) from cash flow hedges		4		(3)
Total accumulated other comprehensive loss	$	(44)	$	(48)

(8) 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. At December 31, 2007, 322,718,951 shares of CenterPoint Energy common stock were issued and 322,718,785 shares of CenterPoint Energy common stock were outstanding. At June 30, 2008, 341,778,170 shares of CenterPoint Energy common stock were issued and 341,778,004 shares of CenterPoint Energy common stock were outstanding. See Note 9(b) describing the conversion of the 3.75% Convertible Senior Notes in the first six months of 2008. Outstanding common shares exclude 166 treasury shares at both December 31, 2007 and June 30, 2008.

(9) Short-term Borrowings and 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 ranges 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 June 30, 2008, the facility size was $200 million. As of December 31, 2007 and June 30, 2008, $232 million and $200 million, respectively, was advanced for the purchase of receivables under CERC's receivables facility.

(b) Long-term Debt

Senior Notes. In May 2008, the Company issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.50%. The proceeds from the sale of the senior notes were used for general corporate purposes, including the satisfaction of cash payment obligations in connection with conversions of the Company's 3.75% convertible senior notes.

In May 2008, CERC Corp. issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.00%. The proceeds from the sale of the senior notes were used for general corporate purposes, including capital expenditures, working capital and loans to or investments in affiliates. Pending application of the net proceeds from this offering for these purposes, CERC Corp. repaid approximately $30 million of borrowings under its senior unsecured revolving credit facility and used the remainder of the net proceeds from the offering to repay borrowings from its affiliates.

Revolving Credit Facilities. As of December 31, 2007 and June 30, 2008, the following balances were outstanding under the Company's revolving credit facilities (in millions):

	December 31, 2007	June 30, 2008
CenterPoint Energy $1.2 billion credit facility:		
Borrowings	$ 131	$ 290
Commercial paper	—	90
Total outstanding	$ 131	$ 380
CenterPoint Houston $300 million credit facility:		
Borrowings	$ 50	$ 102
Total outstanding	$ 50	$ 102
CERC Corp. $950 million credit facility:		
Borrowings	$ 150	$ —
Commercial paper	—	40
Total outstanding	$ 150	$ 40

In addition, as of June 30, 2008, the Company had approximately $28 million of outstanding letters of credit under its $1.2 billion credit facility and CenterPoint Houston had approximately $4 million of outstanding letters of credit under its $300 million credit facility. The Company, CenterPoint Houston and CERC Corp. were in compliance with all debt covenants as of June 30, 2008.

Convertible Debt. In April 2008, the Company announced a call for redemption of its 3.75% convertible senior notes on May 30, 2008. At the time of the announcement, the notes were convertible at the option of the holders, and substantially all of the notes were submitted for conversion on or prior to the May 30, 2008 redemption date. During the six months ended June 30, 2008, the Company issued 16.9 million shares of its common stock and paid cash of approximately $532 million to settle conversions of approximately $535 million principal amount of its 3.75% convertible senior notes.

Purchase of Pollution Control Bonds. In April 2008, the Company purchased $175 million principal amount of pollution control bonds issued on its behalf at 102% of their principal amount. Prior to the purchase, $100 million principal amount of such bonds had a fixed rate of interest of 7.75% and $75 million principal amount of such bonds had a fixed rate of interest of 8%. Depending on market conditions, the Company expects to remarket both series of bonds, at 100% of their principal amounts, in 2008.

(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, 2007 and June 30, 2008 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 June 30, 2008, minimum payment obligations for natural gas supply commitments are approximately $513 million for the remaining six months in 2008, $594 million in 2009, $319 million in 2010, $305 million in 2011, $294 million in 2012 and $1.3 billion after 2012.

(b) 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 Reliant Energy, Inc. (formerly Reliant Resources, Inc.) (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 "Gas Market Manipulation Cases," "Electricity 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.

Gas Market Manipulation Cases. A large number of lawsuits were filed against numerous gas market participants in a number of federal and western state courts in connection with the operation of the natural gas markets in 2000-2001. The Company's former affiliate, RRI, was a participant in gas trading in the California and Western markets. These lawsuits, many of which have been filed as class actions, allege violations of state and federal antitrust laws. Plaintiffs in these lawsuits are seeking a variety of forms of relief, including recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages, full consideration damages, punitive damages, injunctive relief, interest due, civil penalties and fines, costs of suit and attorneys' fees. The Company and/or Reliant Energy were named in approximately 30 of these lawsuits, which were instituted between 2003 and 2007. In October 2006, RRI reached a settlement of 11 class action natural gas cases pending in state court in California. The court approved this settlement in June 2007. In the other gas cases consolidated 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 the Company was dismissed from these suits in April 2008. In the Nevada federal litigation, three of the complaints were dismissed based on defendants' filed rate doctrine defense, but the Ninth Circuit Court of Appeals reversed those dismissals and remanded the cases back to the district court for further proceedings. In July 2008, the plaintiffs in four of the federal court cases agreed to dismiss the Company from those cases. A suit remains pending in Nevada state court in Clark County and five other suits consolidated under multidistrict litigation rules are pending in federal district court in Nevada. The Company believes it is not a proper defendant in the remaining cases and will continue to seek dismissal from those cases.

Electricity Market Manipulation Cases. A large number of lawsuits were filed against numerous market participants in connection with the operation of the California electricity markets in 2000-2001. The Company's former affiliate, 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 was a defendant in approximately five of these suits. These lawsuits, many of which were filed as class actions, were 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. In August 2005, RRI reached a settlement with the Federal Energy Regulatory Commission (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 has been approved by the FERC, by the California Public Utilities Commission and by the courts in which the electricity class action cases were pending. Two parties appealed the courts' approval of the settlement to the California Court of Appeals, but that appeal was denied and the deadline to appeal to the California Supreme Court has passed. 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.

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 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 (Fifth Circuit). In April 2008, the Fifth Circuit affirmed the district court’s ruling, and that ruling is not subject to further review.

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., CenterPoint Energy Pipeline Services, Inc. (CEPS), and certain other subsidiaries of CERC, 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 by certain CERC ratepayers in Texas and Arkansas in circuit court in Miller County, Arkansas against the Company, CERC, EGMC, CenterPoint Energy Gas Transmission Company (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 CEGT and MRT as defendants. Although the plaintiffs in the Miller County case sought class certification, no class was certified. In June 2007, the Arkansas Supreme Court determined that the Arkansas claims were within the sole and exclusive jurisdiction of the Arkansas Public Service Commission (APSC). In response to that ruling, in August 2007 the Miller County court stayed but refused to dismiss the Arkansas claims. In February 2008, the Arkansas Supreme Court directed the Miller County court to dismiss the entire case for lack of jurisdiction. The Miller County court subsequently dismissed the case in accordance with the Arkansas Supreme Court's mandate and all appellate deadlines have expired.

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 October 2007, CEFS and CEPS were joined as plaintiffs to the Travis County case.

In August 2007, the Arkansas plaintiff in the Miller County litigation 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. That complaint remains pending at the APSC.

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. The refund will be completed in the fourth quarter of 2008. 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

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 June 30, 2008, 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 June 30, 2008, 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.

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 December 2007, the Company, CERC and RRI amended that agreement and CERC released the letters of credit it held as security. Under the revised agreement 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 potential exposure of CERC under the guaranties relates to payment of demand charges related to transportation contracts. RRI continues to meet its obligations under the contracts, and, on the basis of current market conditions, the Company and CERC believe that additional security is not needed at this time. However, if RRI should fail to perform its obligations under the contracts or if RRI should fail to provide adequate security in the event market conditions change adversely, the Company would retain exposure to the counterparty under the guaranty.

(11) Income Taxes

During the three months and six months ended June 30, 2007, the effective tax rate was 29% and 33%, respectively. During each of the three and six months ended June 30, 2008, the effective tax rate was 38%. The most significant item affecting the comparability of the effective tax rate is the 2008 classification of approximately $3 million and $7 million for the three and six months ended June 30, 2008, respectively, of Texas margin tax as an income tax for CenterPoint Houston.

The following table summarizes the Company's liability for uncertain tax positions in accordance with FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109," at December 31, 2007 and June 30, 2008 (in millions):

	December 31,	June 30,

	2007	2008
Liability for uncertain tax positions	$ 82	$ 95
Portion of liability for uncertain tax positions that, if recognized, would reduce the effective income tax rate	10	12
Interest accrued on uncertain tax positions	4	6

(12) Earnings Per Share

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

	For the Three Months Ended June 30, 2007	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2007	For the Six Months Ended June 30, 2008
	(in millions, except share and per share amounts)			
Basic earnings per share calculation:				
Net income	$ 70	$ 101	$ 200	$ 224
Weighted average shares outstanding	320,927,000	331,354,000	319,501,000	329,316,000
Basic earnings per share	$ 0.22	$ 0.30	$ 0.62	$ 0.68
Diluted earnings per share calculation:				
Net income	$ 70	$ 101	$ 200	$ 224
Weighted average shares outstanding	320,927,000	331,354,000	319,501,000	329,316,000
Plus: Incremental shares from assumed conversions:				
Stock options (1)	1,204,000	881,000	1,157,000	860,000
Restricted stock units	1,543,000	1,334,000	1,543,000	1,334,000
2.875% convertible senior notes	—	—	586,000	—
3.75% convertible senior notes	20,096,000	8,458,000	19,237,000	9,363,000
Weighted average shares assuming dilution	343,770,000	342,027,000	342,024,000	340,873,000
Diluted earnings per share	$ 0.20	$ 0.30	$ 0.58	$ 0.66

(1) Options to purchase 2,609,420 shares and 3,313,479 shares were outstanding for the three and six months ended June 30, 2007, respectively, and options to purchase 2,760,792 shares and 2,762,913 shares were outstanding for the three and six months ended June 30, 2008, respectively, but were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares for the respective periods.

Substantially all of the 3.75% contingently convertible senior notes provided 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 included 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 exceeded the conversion price. In April 2008, the Company announced a call for redemption of its 3.75% convertible senior notes on May 30, 2008. At the time of the announcement, the notes were convertible at the option of the holders, and substantially all of the notes were submitted for conversion on or prior to the May 30, 2008 redemption date. During the six months ended June 30, 2008, the Company issued 16.9 million shares of its common stock and paid cash of approximately $532 million to settle conversions of approximately $535 million principal amount of its 3.75% convertible senior notes.

(13) 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 business segment 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.

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

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

	For the Three Months Ended June 30, 2007		
	Revenues from External Customers	Net Intersegment Revenues	Operating Income (Loss)
Electric Transmission & Distribution	$ 465(1)	$ —	$ 157
Natural Gas Distribution	573	3	8
Competitive Natural Gas Sales and Services	874	7	(4)
Interstate Pipelines	88	33	52
Field Services	30	12	27
Other Operations	3	—	2
Eliminations	—	(55)	—
Consolidated	$ 2,033	$ —	$ 242

	For the Three Months Ended June 30, 2008		
	Revenues from External Customers	Net Intersegment Revenues	Operating Income (Loss)
Electric Transmission & Distribution	$ 510(1)	$ —	$ 164(3)
Natural Gas Distribution	724	2	4
Competitive Natural Gas Sales and Services	1,234	9	(5)
Interstate Pipelines	150	42	101(4)
Field Services	50	12	32
Other Operations	2	—	1
Eliminations	—	(65)	—
Consolidated	$ 2,670	$ —	$ 297

	For the Six Months Ended June 30, 2007			
	Revenues from External Customers	Net Intersegment Revenues	Operating Income	Total Assets as of December 31, 2007
Electric Transmission & Distribution	$ 871(1)	$ —	$ 261	$ 8,358
Natural Gas Distribution	2,137	6	137	4,332
Competitive Natural Gas Sales and Services	1,921	24	52	1,221
Interstate Pipelines	147	64	96	3,007
Field Services	58	23	49	669
Other Operations	5	—	—	1,956(2)
Eliminations	—	(117)	—	(1,671)
Consolidated	$ 5,139	$ —	$ 595	$ 17,872

	For the Six Months Ended June 30, 2008			
	Revenues from External	Net Intersegment Revenues	Operating Income	Total Assets

	Customers			as of June 30, 2008
Electric Transmission & Distribution	$ 919(1)	$ —	$ 255(3)	$ 8,338
Natural Gas Distribution	2,421	5	125	4,213
Competitive Natural Gas Sales and Services	2,343	20	1	1,498
Interstate Pipelines	241	84	172(4)	3,464
Field Services	104	16	77	759
Other Operations	5	—	3	1,771(2)
Eliminations	—	(125)	—	(1,967)
Consolidated	$ 6,033	$ —	$ 633	$ 18,076

(1) Sales to subsidiaries of RRI in each of the three months ended June 30, 2007 and 2008 represented approximately $151 million of CenterPoint Houston's transmission and distribution revenues. Sales to subsidiaries of RRI in the six months ended June 30, 2007 and 2008 represented approximately $300 million and $293 million, respectively.

(2) Included in total assets of Other Operations as of December 31, 2007 and June 30, 2008 are pension assets of $231 million and $242 million, respectively. Also included in total assets of Other Operations as of December 31, 2007 and June 30, 2008, are pension related regulatory assets of $319 million and $314 million, respectively, which resulted from the Company's 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)."

(3) Included in operating income of Electric Transmission & Distribution for the three and six months ended June 30, 2008 is a $9 million gain on sale of land.

(4) Included in operating income of Interstate Pipelines for the three and six months ended June 30, 2008 is an $18 million gain on the sale of two storage development projects.

(14) Subsequent Event

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

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS OF CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

The following discussion and analysis should be read in combination with our Interim Condensed Financial Statements contained in this Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2007 (2007 Form 10-K).

EXECUTIVE SUMMARY

Recent Events

Debt Financing Transactions

In April 2008, we purchased $175 million principal amount of pollution control bonds issued on our behalf at 102% of their principal amount. Prior to the purchase, $100 million principal amount of such bonds had a fixed rate of interest of 7.75% and $75 million principal amount of such bonds had a fixed rate of interest of 8%. Depending on market conditions, we expect to remarket both series of bonds, at 100% of their principal amounts, in 2008.

In April 2008, we announced a call for redemption of our 3.75% convertible senior notes on May 30, 2008. At the time of the announcement, the notes were convertible at the option of the holders, and substantially all of the notes were submitted for conversion on or prior to the May 30, 2008 redemption date. During the six months ended June 30, 2008, we issued 16.9 million shares of our common stock and paid cash of approximately $532 million to settle conversions of approximately $535 million principal amount of our 3.75% convertible senior notes.

In May 2008, we issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.50%. The proceeds from the sale of the senior notes were used for general corporate purposes, including the satisfaction of cash payment obligations in connection with conversions of our 3.75% convertible senior notes as discussed above.

In May 2008, CenterPoint Energy Resources Corp. (CERC Corp., together with its subsidiaries, CERC) issued $300 million aggregate principal amount of senior notes due in May 2018 with an interest rate of 6.00%. The proceeds from the sale of the senior notes were used for general corporate purposes, including capital expenditures, working capital and loans to or investments in affiliates. Pending application of the net proceeds from this offering for these purposes, CERC Corp. repaid approximately $30 million of borrowings under its senior unsecured revolving credit facility, which terminates in 2012, and used the remainder of the net proceeds from the offering to repay borrowings from its affiliates.

Interstate Pipeline Expansion

In May 2007, CenterPoint Energy Gas Transmission (CEGT), a wholly owned subsidiary of CERC Corp., received Federal Energy Regulatory Commission (FERC) approval for the third phase of its Carthage to Perryville pipeline project, 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, to expand capacity of the pipeline to 1.5 billion cubic feet (Bcf) per day by adding additional compression and operating at higher pressures. 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. In March 2008, CEGT met these conditions and gave notice to PHMSA that it would be increasing the pressure in 30 days. In April 2008, CEGT raised the maximum allowable pressure and concurrently placed the phase three expansion in service. The Carthage to Perryville pipeline can now operate at up to 1.5 Bcf per day.

Effective April 1, 2008, Mississippi River Transmission Corp., a wholly owned subsidiary of CERC Corp., signed a 5-year extension of its firm transportation and storage contracts with Laclede Gas Company (Laclede). In 2007, approximately 10% of Interstate Pipelines' operating revenues was attributable to services provided to Laclede.

Southeast Supply Header. Construction continues on the Southeast Supply Header (SESH) pipeline project which began in November 2007. SESH expects to complete construction of the pipeline in the second half of 2008. We have experienced increased costs and now expect SESH's net costs after Southern Natural Gas' contribution to be approximately $1.2 billion, our share of which we expect to be approximately $600 million.

CONSOLIDATED RESULTS OF OPERATIONS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2008	2007	2008
Revenues	$ 2,033	$ 2,670	$ 5,139	$ 6,033
Expenses	1,791	2,373	4,544	5,400
Operating Income	242	297	595	633
Interest and Other Finance Charges	(119)	(113)	(242)	(228)
Interest on Transition Bonds	(32)	(35)	(63)	(68)
Other Income, net	7	14	10	23
Income Before Income Taxes	98	163	300	360
Income Tax Expense	(28)	(62)	(100)	(136)
Net Income	$ 70	$ 101	$ 200	$ 224
Basic Earnings Per Share	$ 0.22	$ 0.30	$ 0.62	$ 0.68
Diluted Earnings Per Share	$ 0.20	$ 0.30	$ 0.58	$ 0.66

Three months ended June 30, 2008 compared to three months ended June 30, 2007

We reported consolidated net income of $101 million ($0.30 per diluted share) for the three months ended June 30, 2008 as compared to $70 million ($0.20 per diluted share) for the same period in 2007. The increase in net income of $31 million was primarily due to increased operating income of $49 million in our Interstate Pipelines business segment, decreased interest expense of $6 million, excluding transition bonds, and increased operating income of $5 million in our Field Services business segment, partially offset by increased income tax expense of $34 million and decreased operating income of $4 million in our Natural Gas Distribution business segment.

Six months ended June 30, 2008 compared to six months ended June 30, 2007

We reported consolidated net income of $224 million ($0.66 per diluted share) for the six months ended June 30, 2008 as compared to $200 million ($0.58 per diluted share) for the same period in 2007. The increase in net income of $24 million was primarily due to increased operating income of $76 million in our Interstate Pipelines business segment, increased operating income of $28 million in our Field Services business segment and decreased interest expense of $14 million, excluding interest on transition bonds, partially offset by decreased operating income of $51 million in our Competitive Natural Gas Sales and Services business segment, increased income tax expense of $36 million, decreased operating income of $13 million from our electric transmission and distribution utility and decreased operating income of $12 million in our Natural Gas Distribution business segment.

Income Tax Expense

During the three months and six months ended June 30, 2007, the effective tax rate was 29% and 33%, respectively. During each of the three and six months ended June 30, 2008, the effective tax rate was 38%. The most significant item affecting the comparability of the effective tax rate is the 2008 classification of approximately $3 million and $7 million for the three and six months ended June 30, 2008, respectively, of Texas margin tax as an income tax for CenterPoint Houston.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for the three and six months ended June 30, 2007 and 2008.

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Ended June 30, 2008
Electric Transmission & Distribution	$ 157	$ 164	$ 261	$ 255
Natural Gas Distribution	8	4	137	125
Competitive Natural Gas Sales and Services	(4)	(5)	52	1
Interstate Pipelines	52	101	96	172
Field Services	27	32	49	77
Other Operations	2	1	—	3
Total Consolidated Operating Income	$ 242	$ 297	$ 595	$ 633

Electric Transmission & Distribution

For information regarding factors that may affect the future results of operations of our Electric Transmission & Distribution business segment, please read "Risk Factors — Risk Factors Affecting Our Electric Transmission & Distribution Business," "— Risk Factors Associated with Our Consolidated Financial Condition" and "— Risks Common t Our Business and Other Risks" in Item 1A of Part I of our 2007 Form 10-K.

The following tables provide summary data of our Electric Transmission & Distribution business segment for the three and six months ended June 30, 2007 and 2008 (in millions, except throughput and customer data):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Ended June 30, 2008
Revenues:				
Electric transmission and distribution utility	$ 395	$ 419	$ 742	$ 765
Transition bond companies	70	91	129	154
Total revenues	465	510	871	919
Expenses:				
Operation and maintenance, excluding transition bond companies	150	167	304	335
Depreciation and amortization, excluding transition bond companies	61	71	124	137
Taxes other than income taxes	56	52	113	105
Transition bond companies	41	56	69	87
Total expenses	308	346	610	664
Operating Income	$ 157	$ 164	$ 261	$ 255
Operating Income:				
Electric transmission and distribution utility	$ 118	$ 129	$ 180	$ 183

Competition transition charge	10	—	21	5
Transition bond companies (1)	29	35	60	67
Total segment operating income	$ 157	$ 164	$ 261	$ 255
Throughput (in gigawatt-hours (GWh)):				
Residential	6,021	6,774	10,679	11,177
Total	19,175	20,360	35,835	36,929
Average number of metered customers:				
Residential	1,767,749	1,814,840	1,760,006	1,808,056
Total	2,006,840	2,058,171	1,998,291	2,050,316

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

Three months ended June 30, 2008 compared to three months ended June 30, 2007

Our Electric Transmission & Distribution business segment reported operating income of $164 million for the three months ended June 30, 2008, consisting of $129 million from the regulated electric transmission and distribution utility (TDU) and $35 million related to transition bond companies. For the three months ended June 30, 2007, operating income totaled $157 million, consisting of $118 million from the TDU, exclusive of an additional $10 million from the competition transition charge (CTC), and $29 million related to transition bond companies. Revenues for the TDU increased due to increased usage caused by warmer weather in 2008 compared to 2007 ($16 million), continued customer growth ($6 million), with almost 52,000 metered customers added since June 30, 2007, increased transmission related revenues ($4 million) and increased ancillary services ($3 million), partially offset by the settlement of the final fuel reconciliation in 2007 ($4 million). Operation and maintenance expense increased primarily due to higher transmission costs ($9 million), the settlement of the final fuel reconciliation in 2007 ($13 million) and increased support services ($3 million), partially offset by a gain on sale of land ($9 million). Depreciation and amortization increased $10 million primarily due to amounts related to the CTC which are offset by similar amounts in revenues in 2007 ($8 million). Taxes other than income taxes declined $4 million primarily as a result of Texas margin taxes being classified as an income tax for financial reporting purposes in 2008.

Six months ended June 30, 2008 compared to six months ended June 30, 2007

Our Electric Transmission & Distribution business segment reported operating income of $255 million for the six months ended June 30, 2008, consisting of $183 million from the TDU, exclusive of an additional $5 million from the CTC, and $67 million related to transition bond companies. For the six months ended June 30, 2007, operating income totaled $261 million, consisting of $180 million from the TDU, exclusive of an additional $21 million from the CTC, and $60 million related to transition bond companies. Revenues for the TDU increased due to customer growth, with almost 52,000 metered customers added since June 30, 2007 ($12 million), increased usage ($6 million) caused by warmer weather experienced during the second quarter of 2008 reduced by conservation, increased transmission related revenues ($9 million) and increased ancillary services ($6 million), partially offset by the settlement of the final fuel reconciliation in 2007 ($4 million). Operation and maintenance expense increased primarily due to higher transmission costs ($17 million), the settlement of the final fuel reconciliation in 2007 ($13 million) and increased support services ($7 million), partially offset by a gain on sale of land ($9 million). Depreciation and amortization increased $13 million primarily due to amounts related to the CTC which are offset by similar amounts in revenues in 2007 ($10 million). Taxes other than income taxes declined $8 million primarily as a result of the Texas margin tax being classified as an income tax for financial reporting purposes in 2008.

Natural Gas Distribution

For information regarding factors that may affect the future results of operations of our Natural Gas Distribution business segment, please read “Risk Factors — Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines and Field Services Businesses,” “— Risk Factors Associated with Our Consolidated Financial Condition” and “— Risks Common to Our Business and Other Risks” in Item 1A of Part I of our 2007 Form 10-K.

The following table provides summary data of our Natural Gas Distribution business segment for the three and six months ended June 30, 2007 and 2008 (in millions, except throughput and customer data):

26

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2008	2007	2008
Revenues	$ 576	$ 726	$ 2,143	$ 2,426
Expenses:				
Natural gas	366	512	1,578	1,845
Operation and maintenance	135	141	282	297
Depreciation and amortization	38	39	76	78
Taxes other than income taxes	29	30	70	81
Total expenses	568	722	2,006	2,301
Operating Income	$ 8	$ 4	$ 137	$ 125
Throughput (in Bcf):				
Residential	20	20	106	104
Commercial and industrial	44	47	126	130
Total Throughput	64	67	232	234
Average number of customers:				
Residential	2,925,120	2,956,291	2,935,661	2,965,941
Commercial and industrial	247,550	249,776	246,564	250,382
Total	3,172,670	3,206,067	3,182,225	3,216,323

Three months ended June 30, 2008 compared to three months ended June 30, 2007

Our Natural Gas Distribution business segment reported operating income of $4 million for the three months ended June 30, 2008 compared to operating income of $8 million for the three months ended June 30, 2007. Operating margin (revenues less the cost of gas) increased $4 million primarily as a result of rate increases ($3 million), customer growth ($1 million) from the addition of nearly 34,000 customers since June 30, 2007, and recovery of higher gross receipts taxes ($2 million), which are offset in other tax expense, partially offset by weather and the cost of the weather hedge ($2 million). Operation and maintenance expenses increased $6 million primarily as a result of increased bad debt and collection efforts ($4 million) and higher customer-related costs and support services ($7 million), partially offset by lower employee-related costs ($4 million).

Six months ended June 30, 2008 compared to six months ended June 30, 2007

Our Natural Gas Distribution business segment reported operating income of $125 million for the six months ended June 30, 2008 compared to operating income of $137 million for the six months ended June 30, 2007. Operating margin improved $16 million primarily as a result of rate increases ($8 million), growth from the addition of nearly 34,000 customers since June 30, 2007 ($3 million), recovery of higher gross receipts taxes ($10 million) and energy-efficiency costs ($4 million), both of which are offset by the related expenses. These margin increases were partially offset by lower use per customer and the cost of the weather hedge ($16 million). Operation and maintenance expenses increased $15 million primarily as a result of increased bad debt and collection efforts ($6 million), higher customer-related costs and support services ($7 million) and increased costs of materials and supplies ($2 million), partially offset by lower employee-related costs ($6 million).

Competitive Natural Gas Sales and Services

For information regarding factors that may affect the future results of operations of our Competitive Natural Gas Sales and Services business segment, please read "Risk Factors — Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines and Field Services Businesses," "— Risk Factors Associated with Our Consolidated Financial Condition" and "— Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2007 Form 10-K.

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for the three and six months ended June 30, 2007 and 2008 (in millions, except throughput and customer data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2008	2007	2008
Revenues	$ 881	$ 1,243	$ 1,945	$ 2,363
Expenses:				
Natural gas	877	1,237	1,875	2,342
Operation and maintenance	7	10	16	18
Depreciation and amortization	1	—	1	1
Taxes other than income taxes	—	1	1	1
Total expenses	885	1,248	1,893	2,362
Operating Income (Loss)	$ (4)	$ (5)	$ 52	$ 1
Throughput (in Bcf)	120	129	275	267
Average number of customers	7,077	9,186	7,032	8,840

Three months ended June 30, 2008 compared to three months ended June 30, 2007

Our Competitive Natural Gas Sales and Services business segment reported an operating loss of $5 million for the three months ended June 30, 2008 compared to an operating loss of $4 million for the three months ended June 30, 2007. The decrease in operating income of $1 million in the second quarter of 2008 was primarily due to an increase in operating expenses, excluding natural gas, of $3 million compared to the same period last year. The second quarter of 2008 included charges of $10 million resulting from mark-to-market accounting for derivatives used to lock in economic margins of certain forward natural gas sales compared to mark-to-market charges of $6 million for the same period of 2007.

Six months ended June 30, 2008 compared to six months ended June 30, 2007

Our Competitive Natural Gas Sales and Services business segment reported operating income of $1 million for the six months ended June 30, 2008 compared to $52 million for the six months ended June 30, 2007. The decrease in operating income of $51 million was due in part to higher operating margins (revenues less natural gas costs) in 2007 related to sales of gas from inventory that was written down to the lower of cost or market in 2006 of $18 million. Our Competitive Natural Gas Sales and Services business segment purchases and stores natural gas to meet certain future sales requirements and enters into derivative contracts to hedge the economic value of the future sales. The unfavorable mark-to-market accounting for non-trading financial derivatives for the first six months of 2008 of $32 million versus $14 million for the same period in 2007 accounted for a further net $18 million decrease in operating margins. The additional decrease in operating income of $15 million for the first six months ended June 30, 2008 compared to the same period last year was primarily due to a reduction in margin as basis and summer/winter spreads narrowed.

Interstate Pipelines

For information regarding factors that may affect the future results of operations of our Interstate Pipelines business segment, please read “Risk Factors — Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines and Field Services Businesses,” “— Risk Factors Associated with Our Consolidated Financial Condition” and “— Risks Common to Our Business and Other Risks” in Item 1A of Part I of our 2007 Form 10-K.

The following table provides summary data of our Interstate Pipelines business segment for the three and six months ended June 30, 2007 and 2008 (in millions, except throughput data):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Ended June 30, 2008
Revenues	$ 121	$ 192	$ 211	$ 325
Expenses:				
Natural gas	24	58	28	73
Operation and maintenance	29	16	56	46
Depreciation and amortization	11	11	21	23
Taxes other than income taxes	5	6	10	11
Total expenses	69	91	115	153
Operating Income	$ 52	$ 101	$ 96	$ 172
Transportation throughput (in Bcf)	274	361	568	785

Three months ended June 30, 2008 compared to three months ended June 30, 2007

Our Interstate Pipeline business segment reported operating income of $101 million for the three months ended June 30, 2008 compared to $52 million for the three months ended June 30, 2007. The increase in operating income was primarily from the Carthage to Perryville pipeline that went into service in May 2007 ($12 million), increased transportation and ancillary services ($22 million) and a gain on the sale of two storage development projects ($18 million), partially offset by increased operating expenses ($4 million).

Six months ended June 30, 2008 compared to six months ended June 30, 2007

Our Interstate Pipeline business segment reported operating income of $172 million for the six months ended June 30, 2008 compared to $96 million for the six months ended June 30, 2007. The increase in operating income was primarily due to operating the Carthage to Perryville pipeline Phase I and II for six months and Phase III for three months ($31 million), increased transportation and ancillary services ($32 million) and a gain on the sale of two storage development projects ($18 million), partially offset by an increase in operating expenses ($5 million).

Field Services

For information regarding factors that may affect the future results of operations of our Field Services business segment, please read “Risk Factors — Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines and Field Services Businesses,” “— Risk Factors Associated with Our Consolidated Financial Condition” and “— Risks Common to Our Business and Other Risks” in Item 1A of Part I of our 2007 Form 10-K.

The following table provides summary data of our Field Services business segment for the three and six months ended June 30, 2007 and 2008 (in millions, except throughput data):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2008	Six Months Ended June 30, 2007	Six Months Ended June 30, 2008
Revenues	$ 42	$ 62	$ 81	$ 120
Expenses:				
Natural gas	(4)	8	(7)	6
Operation and maintenance	16	18	32	29

Depreciation and amortization		3		3		6		6
Taxes other than income taxes		—		1		1		2
Total expenses		15		30		32		43
Operating Income	$	27	$	32	$	49	$	77
Gathering throughput (in Bcf)		100		104		193		202

Three months ended June 30, 2008 compared to three months ended June 30, 2007

Our Field Services business segment reported operating income of $32 million for the three months ended June 30, 2008 compared to $27 million for the three months ended June 30, 2007. The increase in operating income of $5 million was primarily driven by increased revenues from gas gathering and ancillary services and higher commodity prices, partially offset by increased operating expenses associated with new assets and general cost increases.

In addition, this business segment recorded equity income of $2 million and $4 million in the three months ended June 30, 2007 and 2008, respectively, from its 50 percent interest in a jointly-owned gas processing plant. These amounts are included in Other – net under the Other Income (Expense) caption.

Six months ended June 30, 2008 compared to six months ended June 30, 2007

Our Field Services business segment reported operating income of $77 million for the six months ended June 30, 2008 compared to $49 million for the six months ended June 30, 2007. The increase in operating income of $28 million was primarily driven by a one-time gain ($11 million) related to a settlement and contract buyout of one of our customers and a one-time gain ($6 million) related to the sale of assets, both recognized in the first quarter of 2008. In addition to these one-time items, increased revenues from gas gathering and ancillary services and higher commodity prices were partially offset by increased operating expenses associated with new assets and general cost increases.

In addition, this business segment recorded equity income of $4 million and $8 million in the six months ended June 30, 2007 and 2008, respectively, from its 50 percent interest in a jointly-owned gas processing plant. These amounts are included in Other – net under the Other Income (Expense) caption.

Other Operations

The following table shows the operating income of our Other Operations business segment for the three and six months ended June 30, 2007 and 2008 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2008	2007	2008
Revenues	$ 3	$ 2	$ 5	$ 5
Expenses	1	1	5	2
Operating Income	$ 2	$ 1	$ —	$ 3

30

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

For information on other developments, factors and trends that may have an impact on our future earnings, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Future Earnings" in Item 7 of Part II and "Risk Factors" in Item 1A of Part I of our 2007 Form 10-K, and "Cautionary Statement Regarding Forward-Looking Information."

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flows

The following table summarizes the net cash provided by (used in) operating, investing and financing activities for the six months ended June 30, 2007 and 2008:

	Six Months Ended June 30,
	2007