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

Form 10-K/A

Amendment No. 1

(Mark One)

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

For the fiscal year ended December 31, 2001

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 1-3187

Reliant Energy, Incorporated

(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) 207-3000 *(Registrant's telephone number, including area code)*

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

Title of each class	Name of each exchange on which registered
Common Stock, without par value and associated rights to purchase preference stock	New York Stock Exchange Chicago Stock Exchange
HL&P Capital Trust I 8.125% Trust Preferred Securities, Series A	New York Stock Exchange
REI Trust I 7.20% Trust Originated Preferred Securities, Series C	New York Stock Exchange
9.15% First Mortgage Bonds due 2021	New York Stock Exchange

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

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

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

The aggregate market value of the voting stock held by non-affiliates of Reliant Energy, Incorporated (Company) was $7,365,940,777 as of April 8, 2002, using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of April 8, 2002, the Company had 303,496,317 shares of Common Stock outstanding, including 6,023,880 ESOP shares not deemed outstanding for financial statement purposes. Excluded from the number of shares of Common Stock outstanding are 166 shares held by the Company as treasury stock.

Portions of the definitive proxy statement relating to the 2002 Annual Meeting of Shareholders of the Company, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2001, are incorporated by reference in Item 10, Item 11, Item 12 and Item 13 of Part III of this Form 10-K.

Reliant Energy, Incorporated (Reliant Energy) hereby amends Items 1, 6, 7 and 8 of its Annual Report of Form 10-K for the year ended December 31, 2001 as originally filed on April 15, 2002.

Restatement

On May 9, 2002, Reliant Resources, Inc. (Reliant Resources), an entity in which Reliant Energy owns approximately 83% of the outstanding common stock, determined that it had engaged in same-day commodity trading transactions involving purchases and sales with the same counterparty for the same volume at substantially the same price, which the personnel who effected these transactions apparently did so with the sole objective of increasing volumes. Reliant Resources commenced a review to quantify the amount and assess the impact of these trades (round trip trades). The Audit Committees of each of the Board of Directors of Reliant Energy and Reliant Resources also directed an internal investigation by outside legal counsel, with assistance by outside accountants, of the facts and circumstances relating to the round trip trades and related matters.

We currently report all trading, marketing and risk management services transactions on a gross basis with such transactions being reported in revenues and expenses except primarily for financial gas transactions such as swaps. Therefore, the round trip trades were reflected in both our revenues and expenses. The round trip trades should not have been recognized in revenues or expenses (i.e. they should have been reflected on a net basis). However, since the round trip trades were done at the same volume and substantially the same price, they had no impact on our reported cash flows, operating income or net income. In addition to the round trip trades reported on May 13, 2002, Reliant Resources also identified an additional transaction in 1999, which based on available information, Reliant Resources believes was also recorded with the sole objective of increasing volumes but also resulted in increased revenues and fuel and cost of gas sold expense.

In addition, during the May 2001 through September 2001 time frame, Reliant Resources entered into four structured transactions involving a series of forward or swap contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002 or 2003 (four structured transactions). The four structured transactions were intended to increase future cash flow and earnings and to increase certainty associated with future cash flow and earnings, albeit at the expense of 2001 cash flow and earnings. Each series of contracts in a structure were executed contemporaneously with the same counterparty and were for the same commodities, quantities and locations. The contracts in each structure were offsetting in terms of physical attributes. The transactions that settled in 2001 were previously recorded on a gross basis with such transactions being reported in revenues and expenses which resulted in $1.5 billion of revenues, $364 million in fuel and cost of gas sold and $1.2 billion of purchased power expense being recognized during the period from May 2001 through December 31, 2001. Having further reviewed the transactions, Reliant Resources now believes these transactions should have been accounted for on a net basis.

In the course of Reliant Resources' review, Reliant Resources also identified and determined to record on a net basis several transactions for energy related services (not involving round trip trades) that totaled $85 million over the three year period ended December 31, 2001. These transactions were originally recorded on a gross basis.

During the fourth quarter of 2000, two power generation swap contracts with a fair value of $261 million were terminated and replaced with a substantially similar contract providing for physical delivery and designated to hedge electric generation. The termination of the original contracts and execution of the replacement contract represented a substantive modification to the original contract. As a result, upon termination of the original contracts, a contractual liability representing the fair value of the original contracts and a deferred asset of equal amount should have been recorded. As of January 1, 2001, in connection with the adoption of Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133), the deferred asset should have been recorded as a transition adjustment to other comprehensive loss. The liability and transition adjustment should have been amortized on a straight-line basis over the term of the power generation contract replacing the terminated power generation contracts (through May 2004). We previously did not give accounting recognition to these transactions. As a result, we have restated our Consolidated Balance Sheets as of

December 31, 2000 and 2001 and the Statements of Consolidated Stockholders' Equity and Comprehensive Income for the year ended December 31, 2001, to appropriately account for these transactions as described above. The restatement had no impact on our reported consolidated cash flows, operating income or net income.

As a result, Reliant Energy's consolidated financial statements (Original Consolidated Financial Statements) and related disclosures for 1999, 2000 and 2001 have been restated from amounts previously reported. The principal effects of the restatement on the consolidated financial statements are set forth in Note 1 to the consolidated financial statements contained in this Form 10-K/A.

For purposes of this Form 10-K/A, and in accordance with Rule 12b-15 under the Securities Exchange Act of 1934, as amended, each item of the Form 10-K for the year ended December 31, 2001 as originally filed on April 15, 2002 that was affected by the restatement has been amended to the extent affected and restated in its entirety. **No attempt has been made in this Form 10-K/A to modify or update other disclosures as presented in the original Form 10-K except as required to reflect the effects of the restatement.**

We are a party to numerous lawsuits and regulatory proceedings relating to our trading and marketing activities, including the round trip trades and the four structured transactions, and our activities in the California wholesale market. In addition, various state and federal governmental agencies have commenced investigations relating to such activities. For a description of certain of these lawsuits, proceedings and investigations, please read "Legal Proceedings" in Item 3 of this Form 10-K and Notes 14(f) and 14(g) to our consolidated financial statements, Notes 13 and 15(c) to our interim financial statements included in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002 (First Quarter Form 10-Q), and our Current Report on Form 8-K dated July 3, 2002.

TABLE OF CONTENTS

PART I

Item 1.	Business	1
Item 2.	Properties	52
Item 3.	Legal Proceedings	53
Item 4.	Submission of Matters to a Vote of Security Holders	54

PART II

Item 5.	Market for Common Stock and Related Stockholder Matters	55
Item 6.	Selected Financial Data	56
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	58
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	122
Item 8.	Financial Statements (as Restated) and Supplementary Data	133
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	221

PART III

Item 10.	Directors and Executive Officers	221
Item 11.	Executive Compensation	221
Item 12.	Security Ownership of Certain Beneficial Owners and Management	221
Item 13.	Certain Relationships and Related Transactions	221

PART IV

Item 14.	Exhibits, Financial Statement Schedules and Reports on Form 8-K	221

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," "intend," "may," "plan," "potential," "predict," "should," "will," "forecast," "goal," "objective," "projection," 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 list identifies some of the factors that could cause actual results to differ from those expressed or implied by our forward-looking statements:

- state, federal and international legislative and regulatory developments, including deregulation; re-regulation and restructuring of the electric utility industry; and changes in, or application of environmental, siting and other laws and regulations to which we are subject;
- timing of the implementation of our business separation plan, including the receipt of necessary approvals from the Securities and Exchange Commission (SEC) and an extension relating to a private letter ruling from the Internal Revenue Service (IRS);
- the effects of competition, including the extent and timing of the entry of additional competitors in our markets;
- industrial, commercial and residential growth in our service territories;
- our pursuit of potential business strategies, including acquisitions or dispositions of assets or the development of additional power generation facilities;
- state, federal and other rate regulations in the United States and in foreign countries in which we operate or into which we might expand our operations;
- the timing and extent of changes in commodity prices, particularly natural gas;
- weather variations and other natural phenomena;
- political, legal and economic conditions and developments in the United States and in foreign countries in which we operate or into which we might expand our operations, including the effects of fluctuations in foreign currency exchange rates;
- financial market conditions and the results of our financing efforts;
- ramifications from the bankruptcy filing of Enron Corp.;
- any direct or indirect effect on our business resulting from the September 11, 2001 terrorist attacks or any similar incidents or responses to such incidents;
- the performance of our projects; and
- other factors we discuss in this Form 10-K, including those outlined in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings."

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements.

COMMONLY USED TERMS

Below is a list of terms commonly used in this Form 10-K, along with their definitions or descriptions. Some of the definitions or descriptions below are summaries, and you should refer to the corresponding discussion within this Form 10-K for a complete definition or description.

1935 Act	Public Utility Holding Company Act of 1935
Arkla	Reliant Energy Arkla, a division of RERC Corp.
Bbtu	Billion British thermal units
Bcf	Billion cubic feet
Business Separation Plan	Our amended business separation plan providing for the separation of our generation, transmission and distribution, and retail operations into three different companies and for the separation of its regulated and unregulated businesses into two publicly traded companies, as filed with the Texas Utility Commission
Cal ISO	California Independent System Operator
CenterPoint Energy	CenterPoint Energy, Inc.
CenterPoint Energy Houston	CenterPoint Energy Houston Electric, LLC, the transmission and distribution business of Reliant Energy after the Restructuring
Contractually mandated auctions	Auctions to third parties of the installed generating capacity of our Texas generation business in excess of amounts included in the state mandated auctions
Distribution	The distribution of our remaining equity interest in the common stock of Reliant Resources to our shareholders
Entex	Reliant Energy Entex, a division of RERC Corp.
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, Inc.
ERCOT market	The state of Texas, other than a portion of the panhandle and a portion of the east bordering on Louisiana
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt hours
HAPs	Hazardous air pollutants
IRS	Internal Revenue Service
ISO	Independent System Operator
KWh	Kilowatt-hour
Kyoto Protocol	United Nations Framework Convention on Climate Change
Laclede	Laclede Gas Company
MACT	Maximum achievable control technology
Minnegasco	Reliant Energy Minnegasco, a division of RERC Corp.
MMBtu	Million British thermal units
MMcf	Million cubic feet
MRT	Mississippi River Transmission Corporation
MW	Megawatts

MWh	Megawatt hours
NEA	NEA B.V., the coordinating body for the Dutch electricity generating sector
NOx	Nitrogen oxides
NRC	Nuclear Regulatory Commission
October 3, 2001 Order	Order from the Texas Utility Commission dated October 3, 2001 that established the transmission and distribution rates that became effective January 1, 2002
Orion Power	Orion Power Holdings, Inc.
PJM ISO	PJM Interconnection, L.L.C.
PJM market	Pennsylvania-New Jersey-Maryland market
PJM West market	PJM market in western Pennsylvania
POLR	Provider of last resort
price to beat	The price, as set by the Texas Utility Commission, that retail electric providers affiliated with a former integrated utility charge residential and small commercial customers within their affiliated electric utility's service area
PURPA	Public Utility Regulatory Policies Act of 1978
REFS	Reliant Energy Field Services, Inc.
REGT	Reliant Energy Gas Transmission Company
Reliant Energy HL&P	An unincorporated division of Reliant Energy, formerly an integrated electric utility
Reliant Energy	Reliant Energy, Incorporated
Reliant Energy Services	Reliant Energy Services, Inc.
Reliant Resources	Reliant Resources, Inc.
REMA	Reliant Energy Mid-Atlantic Power Holdings, LLC
REPG	Reliant Energy Power Generation, Inc.
REPGB	Reliant Energy Power Generation Benelux N.V. (formerly UNA N.V.)
REPS	Reliant Energy Pipeline Services, Inc.
RERC	Reliant Energy Resources Corp. and subsidiaries
RERC Corp.	Reliant Energy Resources Corp.
Restructuring	The transactions through which CenterPoint Energy will become the holding company for Reliant Energy and its subsidiaries, Reliant Energy and its subsidiaries will become subsidiaries of CenterPoint Energy, and each share of Reliant Energy common stock will be converted into one share of CenterPoint Energy common stock
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
Separation	The transactions that include the transfers of substantially all of our unregulated businesses to Reliant Resources, the Reliant Resources offering, the Restructuring and the Distribution
SFAS	Statement of Financial Accounting Standards
South Texas Project	South Texas Project Electric Generating Station

state mandated auctions	Auctions of 15% of the output of the installed generating capacity of our Texas generation business required by the Texas Electric Restructuring Law
T&D Utility	The transmission and distribution operations that were formerly part of the integrated electric utility under Reliant Energy HL&P, operated as a functionally separate unit since January 2002 as required by the Texas Electric Restructuring Law
TCR	Transmission Congestion Rights
Texas Electric Restructuring Law	Texas Electric Choice Plan, Texas Utility Code § 39.001, et seq
Texas Genco	Texas Genco, LP and the intermediate subsidiaries through which interests in Texas Genco, LP are held
Texas Genco Option	Option, subject to the completion of the Distribution, granted to Reliant Resources by Reliant Energy to purchase all of the shares of capital stock of Texas Genco owned by CenterPoint Energy after Texas Genco conducts the initial public offering or distribution of no more than 20% of its capital stock
Texas generation business	The generating facilities and operations to be transferred to Texas Genco in the Restructuring
Texas Utility Commission	Public Utility Commission of Texas
TMDL	Total Maximum Daily Load program of the Clean Water Act
we, us, our or similar terms	Reliant Energy and its subsidiaries prior to the Restructuring and CenterPoint Energy and its subsidiaries after the Restructuring
Wires Case	March 31, 2000 filing with the Texas Utility Commission, which resulted in the Commission's October 3, 2001 Order that set the regulated rates for the T&D Utility to be effective when electric competition began

PART I

Item 1. *Business*

OUR BUSINESS

General

We are a diversified international energy services and energy delivery company that provides energy and energy services primarily in North America and Western Europe. Reliant Energy, Incorporated (Reliant Energy), a Texas corporation incorporated in 1906, is the parent company of our consolidated group of companies and is a utility holding company that conducts electric utility operations in Texas. Reliant Energy owns all of the common stock of Reliant Energy Resources Corp. (RERC Corp.), which conducts natural gas distribution and pipeline operations, and of CenterPoint Energy, Inc. (CenterPoint Energy), which does not currently conduct any operations. RERC Corp. is a Delaware corporation that was incorporated in 1996. CenterPoint Energy is a Texas corporation that was incorporated in August 2001 to become the holding company for Reliant Energy following the Restructuring (as defined below). Reliant Energy also owns approximately 83% of the common stock of Reliant Resources, Inc. (Reliant Resources), which conducts non-utility wholesale and retail energy operations. Reliant Resources is a Delaware corporation that was incorporated in August 2000. In this Form 10-K, unless the context indicates otherwise,

- references to "we," "us" or similar terms mean Reliant Energy and its subsidiaries prior to the Restructuring described below and CenterPoint Energy and its subsidiaries after the Restructuring; and
- we refer to RERC Corp. and its subsidiaries as "RERC."

The executive offices of Reliant Energy are located at 1111 Louisiana, Houston, TX 77002 (telephone number 713-207-3000).

Status of Business Separation

We are in the process of separating our regulated and unregulated businesses into two unaffiliated publicly traded companies. In December 2000, we transferred a significant portion of our unregulated businesses to Reliant Resources, which, at the time, was a wholly owned subsidiary. Reliant Resources conducted an initial public offering of approximately 20% of its common stock in May 2001. In December 2001, our shareholders approved an agreement and plan of merger by which the following will occur (which we refer to as the Restructuring):

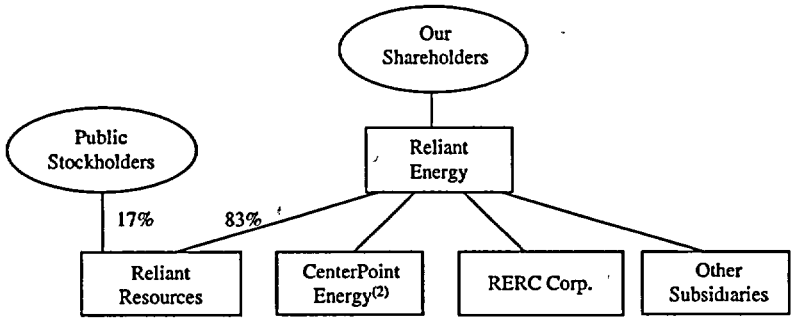
- CenterPoint Energy will become the holding company for Reliant Energy and its subsidiaries;
- Reliant Energy and its subsidiaries will become subsidiaries of CenterPoint Energy; and
- each share of Reliant Energy common stock will be converted into one share of CenterPoint Energy common stock.

After the Restructuring, we plan, subject to further corporate approvals, market and other conditions, to complete the separation of our regulated and unregulated businesses by distributing the shares of common stock of Reliant Resources that we own to our shareholders (Distribution). Our goal is to complete the Restructuring and subsequent Distribution as quickly as possible after all the necessary conditions are fulfilled, including receipt of an order from the SEC granting the required approvals under the Public Utility Holding Company Act of 1935 (1935 Act) and an extension from the IRS for a private letter ruling we have obtained regarding the tax-free treatment of the Distribution. Although receipt or timing of regulatory approvals cannot be assured, we believe we meet the standards for such approvals. Please read "— Regulation — Public Utility Holding Company Act of 1935" in Item 1 of this Form 10-K. We currently expect to complete the Restructuring and Distribution in the summer of 2002. Please read "— Business Separation" in Item 1 of this Form 10-K. For information about an informal inquiry by the staff of the Division of Enforcement of the SEC in connection with an earnings restatement by Reliant Energy that might impact the approval process, please read "Restatement of Second and Third Quarter 2001 Results of Operations" in Item 3 of this Form 10-K.

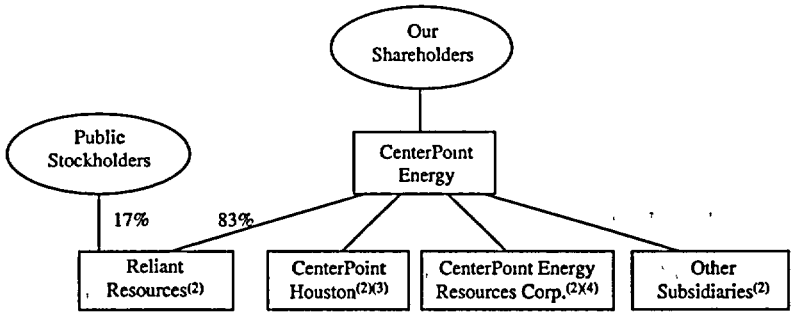
We have entered into a number of separation agreements with Reliant Resources in anticipation of the Restructuring and the Distribution. For information about these agreements, please read "Reliant Energy's Relationship with Reliant Resources" in Item 1 of this Form 10-K.

The diagrams on the following page depict our current structure, our structure after the Restructuring and our structure after the Distribution. Unless otherwise indicated, ownership interests shown below are 100%. Other ownership interests indicated below are approximate.

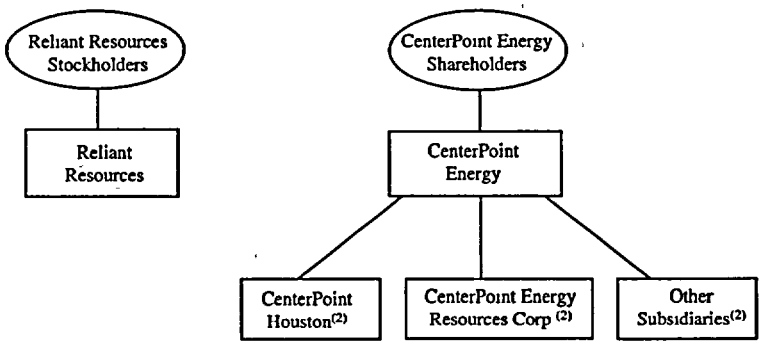
Current Structure[1]



Structure After Restructuring



Structure After Distribution



(1) As of April 1, 2002.

(2) Owned indirectly through another subsidiary of Reliant Energy or CenterPoint Energy.

(3) Reliant Energy will become CenterPoint Energy Houston Electric, LLC (CenterPoint Houston) in the Restructuring. Please read "— Business Separation — Restructuring — Reliant Energy Conversion" in Item 1 of this Form 10-K.

(4) RERC Corp. will be renamed CenterPoint Energy Resources Corp. as part of the Restructuring.

Business Segment Overview

We conducted our operations in 2001 through the following business segments:

- Electric Operations;
- Natural Gas Distribution;
- Pipelines and Gathering;
- Wholesale Energy;
- European Energy;
- Retail Energy;
- Latin America; and
- Other Operations.

During 2001, our Electric Operations business segment included our regulated electric generation, transmission and distribution, and retail electric sales functions, all of which were operated as an integrated utility under Reliant Energy HL&P, an unincorporated division of Reliant Energy. As of January 1, 2002, the generation and retail electric sales functions were deregulated. Retail electric sales involve the sale of electricity and related services to end users of electricity, including industrial, commercial and residential customers. Retail electric sales are now part of the Retail Energy business segment, which is owned by Reliant Resources. The generation facilities now operated as a division of Reliant Energy will be operated by a separate indirect subsidiary of CenterPoint Energy following the Restructuring and will comprise a new business segment, Electric Generation. The transmission and distribution functions, which will be conducted through a separate subsidiary, will remain regulated and will also comprise a new business segment, Electric Transmission and Distribution. In addition to Retail Energy, the Wholesale Energy, European Energy and several of the operations in the Other Operations business segments are currently owned by Reliant Resources. Once we complete the Distribution, those business segments and operations will no longer be part of our business. For more information about our business after deregulation and the completion of the Distribution, please read "Our Business Going Forward" in Item 1 of this Form 10-K.

For information about the revenues, operating income, assets and other financial information relating to our business segments, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations by Business Segment" in Item 7 of this Form 10-K and Note 18 to our consolidated financial statements, which, together with the notes related to those statements, we refer to in this Form 10-K as our "consolidated financial statements."

Deregulation

In 1999, the Texas legislature adopted the Texas Electric Choice Plan (Texas Electric Restructuring Law), which substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition for all customers. Retail pilot projects, allowing competition for up to 5% of each utility's energy demand, or "load" in all customer classes, began in August 2001 and retail electric competition for all other customers began in January 2002. Under the Texas Electric Restructuring Law:

- electric utilities in Texas, including Reliant Energy HL&P, have restructured or are in the process of restructuring their businesses in order to separate power generation, transmission and distribution, and retail electric provider activities into separate units;
- since January 1, 2002, most retail customers of investor-owned electric utilities in Texas, including the customers of Reliant Energy HL&P, have been entitled to purchase their electricity from any of a number of "retail electric providers" that have been certified by the Public Utility Commission of Texas (Texas Utility Commission);

- retail electric providers, who may not themselves own any generation assets, obtain their electricity from power generation companies, exempt wholesale generators and other generating entities and provide services at generally unregulated rates, except that the prices that may be charged to residential and small commercial customers by retail electric providers affiliated with a utility within their affiliated electric utility's service area are set by the Texas Utility Commission (price to beat) until certain conditions in the Texas Electric Restructuring Law are met;

- the transmission and distribution of power are performed by transmission and distribution utilities at rates that continue to be regulated by the Texas Utility Commission; and

- transmission and distribution utilities in Texas whose generation assets were "unbundled" pursuant to the Texas Electric Restructuring Law, including the transmission and distribution utility successor to Reliant Energy HL&P, may recover generation-related

  (i) "regulatory assets," which consist of the Texas jurisdictional amount reported by the electric utilities as regulatory assets and liabilities (offset by specified amounts) in their audited financial statements for 1998; and

  (ii) "stranded costs," which consist of the positive excess of the net regulatory book value of generation assets over the market value of the assets, taking specified factors into account.

We filed our initial business separation plan with the Texas Utility Commission in January 2000 and filed amended plans in April 2000 and August 2000. In December 2000, the Texas Utility Commission approved our amended business separation plan (Business Separation Plan) providing for the separation of our generation, transmission and distribution, and retail operations into three different companies and for the separation of our regulated and unregulated businesses into two publicly traded companies. On October 15, 2001, we filed an update to the Business Separation Plan with the Texas Utility Commission indicating that full implementation of the plan could not be achieved until all regulatory approvals had been received. Since not all regulatory approvals had been received by the beginning of retail competition on January 1, 2002, we have not fully implemented the Business Separation Plan. However, beginning January 1, 2002, our generation, transmission and distribution, and retail electric sales operations have been functionally separated and are conducted independently as if the Business Separation Plan were completed.

The Texas Electric Restructuring Law permits utilities to recover regulatory assets and stranded costs through non-bypassable charges authorized by the Texas Utility Commission, to the extent that such assets and costs are established in certain regulatory proceedings. The law also authorizes the Texas Utility Commission to permit utilities to issue securitization bonds based on the securitization of that charge. On May 31, 2001, the Texas Utility Commission issued a financing order pursuant to the Texas Electric Restructuring Law authorizing the issuance of $740 million of transition bonds, plus approximately $10 million in qualified costs, to recover certain Reliant Energy HL&P regulatory assets. Pursuant to the financing order, we, through a special purpose subsidiary, issued $749 million aggregate principal amount of transition bonds in October 2001 and used the proceeds to reduce our recoverable regulatory assets by repaying outstanding indebtedness. For more information regarding the transition bonds issuance and recovery of our regulatory assets, please read Note 4(a) to our consolidated financial statements. For information regarding the manner in which we plan to recover our stranded costs, please read "Regulation — State and Local Regulations — Texas — Electric Operations — Stranded Costs and Regulatory Assets" in Item 1 of this Form 10-K and Note 4(a) to our consolidated financial statements.

For additional information regarding the Texas Electric Restructuring Law, retail competition in Texas and its application to our operations and structure, please read "— Business Separation," "Electric Operations" and "Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law", below, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Electric Operations" in Item 7 of this Form 10-K and Note 4 to our consolidated financial statements.

Business Separation

Pursuant to the Business Separation Plan, we plan to separate our businesses into two publicly traded companies (CenterPoint Energy and Reliant Resources) in order to separate (i) our unregulated businesses from our regulated businesses and (ii) our generation, transmission and distribution and retail electric sales functions from each other as required by the Texas Electric Restructuring Law. Below is an outline of the significant transactions through which the business separation will be accomplished, some of which have been completed. In this Form 10-K, we sometimes collectively refer to the transactions described below, including the transfers of assets to Reliant Resources, the Reliant Resources offering, the Restructuring and the Distribution as the "Separation."

Reliant Resources Transfers. In December 2000, we transferred substantially all of our unregulated businesses to Reliant Resources, including the operations conducted by our:

- Wholesale Energy business segment;
- European Energy business segment;
- Retail Energy (retail electricity business) business segment;
- Communications business; and
- New Ventures group.

In connection with the transfer of our unregulated businesses to Reliant Resources, we entered into a number of agreements with Reliant Resources, including the master separation agreement, providing for, among other things, the transfer of assets and liabilities to Reliant Resources, as well as interim and ongoing relationships with Reliant Resources, including the provision by Reliant Energy of various interim services to Reliant Resources. For information about these agreements, please read "Reliant Energy's Relationship With Reliant Resources" in Item 1 of this Form 10-K.

In May 2001, Reliant Resources conducted an initial public offering of approximately 20% of its outstanding common stock. Pursuant to the master separation agreement, $1.7 billion of debt owed by Reliant Resources to Reliant Energy was converted into equity as a capital contribution to Reliant Resources in connection with the initial public offering.

Restructuring — Holding Company Formation. After having received the necessary regulatory approvals, CenterPoint Energy will become the holding company for Reliant Energy and its subsidiaries as a result of the merger of a CenterPoint Energy subsidiary with and into Reliant Energy. In the merger, each outstanding share of Reliant Energy common stock will be converted automatically into one share of CenterPoint Energy common stock. For information regarding the special shareholders' meeting at which the merger agreement providing for the holding company formation was approved, please read Item 4 of this Form 10-K.

Restructuring — Texas Genco Transfers. In December 2001, we formed Texas Genco, LP, a Texas limited partnership, as an indirect, wholly owned subsidiary. In this Form 10-K, we refer to Texas Genco, LP and the subsidiary entities through which we own Texas Genco, LP individually and collectively as "Texas Genco," as the context requires. We plan to transfer Reliant Energy HL&P's Texas generating assets and liabilities associated with those assets to Texas Genco immediately prior to the consummation of the holding company formation. Texas Genco will operate our formerly regulated generating assets as a power generation company selling generation at market prices to Reliant Resources and other power purchasers in accordance with the separation agreements and the Texas Electric Restructuring Law and will comprise our new Electric Generation business segment.

In accordance with provisions of the Texas Electric Restructuring Law relating to the determination of stranded costs, we plan for Texas Genco to conduct an initial public offering of approximately 20% of its capital stock by the end of 2002. If we do not conduct the initial public offering, we may distribute approximately 20% of Texas Genco's capital stock to our shareholders in a transaction taxable both to us and our shareholders as part of the valuation of stranded costs. Reliant Resources holds an option, subject to the completion of the Distribution, exercisable in 2004 to purchase the Texas Genco stock owned by CenterPoint

Energy after the initial public offering or distribution. For additional information regarding Texas Genco and Reliant Resources' option to purchase Texas Genco stock, please read "Reliant Energy's Relationship With Reliant Resources" and "Electric Operations — Generation" in Item 1 of this Form 10-K.

Restructuring — Reliant Energy Conversion. As a result of the holding company formation and transfer of assets to Texas Genco, Reliant Energy will become a wholly owned subsidiary of CenterPoint Energy, will hold the transmission and distribution assets previously held by Reliant Energy HL&P and will operate those assets subject to regulation by the Texas Utility Commission. Immediately after the holding company formation, Reliant Energy will convert from a Texas corporation to CenterPoint Houston, a Texas limited liability company.

Distribution. As a result of the holding company formation, CenterPoint Energy will become the owner of all of the shares of Reliant Resources' common stock currently owned by Reliant Energy. We anticipate that, upon completion of the Restructuring and subject to board approval, market and other conditions, CenterPoint Energy will distribute all of the stock it owns in Reliant Resources to CenterPoint Energy's shareholders, effecting the separation of our operations into two unaffiliated publicly traded corporations. We have obtained a private letter ruling from the IRS providing for the tax-free treatment of the Distribution that is predicated on the completion of the Distribution by April 30, 2002. We have requested an extension of this deadline. While there can be no assurance that we will receive the extension, we anticipate that we will receive an extension that allows us to proceed with the Distribution after April 30, 2002.

Please see "— Status of Business Separation" in Item 1 of this Form 10-K for diagrams depicting various stages of the Separation.

RERC Corp. Restructuring

Following the Restructuring, CenterPoint Energy will be a utility holding company under the 1935 Act and as such will be required to register under the 1935 Act unless it qualifies for an exemption. In order to enable CenterPoint Energy to comply with the requirements in the exemption in Section 3(a)(1) of the 1935 Act, we plan to divide the gas distribution businesses conducted by RERC Corp.'s three unincorporated divisions, Reliant Energy Entex (Entex), Reliant Energy Arkla (Arkla) and Reliant Energy Minnegasco (Minnegasco), among three separate business entities. For more information regarding our application under the 1935 Act and regulation under the 1935 Act, please read "Regulation — Public Utility Holding Company Act of 1935" in Item 1 of this Form 10-K. The entity that will hold the Entex assets will also hold RERC Corp.'s natural gas pipelines and gathering businesses. For more information regarding RERC Corp.'s divisions and their operations, please read "Natural Gas Distribution" and "Pipelines and Gathering" in Item 1 of this Form 10-K. In addition to regulatory approvals we have obtained, this restructuring will require approval of the public service commissions of Louisiana, Oklahoma and Arkansas.

RELIANT ENERGY'S RELATIONSHIP WITH RELIANT RESOURCES

Intercompany Agreements

Prior to the initial public offering of Reliant Resources' common stock, Reliant Energy entered into agreements with Reliant Resources providing for the separation of their businesses. These agreements generally provided for the transfer by Reliant Energy of assets relating to Reliant Resources' businesses and the assumption by Reliant Resources of associated liabilities. Reliant Energy also entered into other agreements governing various ongoing relationships between it and Reliant Resources.

Master Separation Agreement. The master separation agreement provides for the separation of Reliant Energy's assets and businesses from those of Reliant Resources. It contains agreements relating to subsequent transactions and several agreements governing the relationship between Reliant Energy and Reliant Resources in the future. The master separation agreement also provides for cross-indemnities intended to place sole financial responsibility on Reliant Resources and its subsidiaries for all liabilities associated with the current and historical businesses and operations they conduct, regardless of the time those liabilities arise, and to place sole financial responsibility for liabilities associated with Reliant Energy's other businesses with Reliant

Energy and its other subsidiaries. Reliant Energy and Reliant Resources also agreed to assume and be responsible for specified liabilities associated with activities and operations of the other party and its subsidiaries to the extent performed for or on behalf of their respective current or historical business. The master separation agreement also contains indemnification provisions under which Reliant Energy and Reliant Resources will each indemnify the other with respect to breaches by the indemnifying party of the master separation agreement or any ancillary agreements.

The master separation agreement provides for the Restructuring and Distribution, including the formation of Texas Genco, although it does not obligate Reliant Energy to effect the Distribution. The agreement requires Texas Genco (and, prior to the Restructuring, Reliant Energy) to auction capacity remaining after it conducts the mandated auctions of its capacity required by the Texas Electric Restructuring Law. After certain deductions, Reliant Resources has the right to purchase 50% (but no less than 50%) of the capacity that would otherwise be auctioned at the prices to be established in the auctions required by the master separation agreement. For more information on these auctions, please read "— Electric Operations — Generation — State Mandated Capacity Auctions" and "— Contractually Mandated Capacity Auctions" in Item 1 of this Form 10-K.

The master separation agreement also requires Reliant Resources to make a payment to Reliant Energy equal to the amount, if any, required to be credited to Reliant Energy by Reliant Energy's affiliated retail electric provider pursuant to the Texas Electric Restructuring Law. This payment, which is sometimes referred to as the "clawback" payment, will be required unless 40% or more of the amount of electric power that was consumed before the onset of retail competition by residential or small commercial customers within Reliant Energy HL&P's service territory is being served by retail electric providers other than Reliant Resources by January 1, 2004. The payment by Reliant Resources will be the lesser of (a) the amount that the price to beat, less non-bypassable delivery charges, is in excess of the prevailing market price of electricity during such period per customer or (b) $150, multiplied by the number of residential or small commercial customers in Reliant Energy HL&P's service territory that are buying electricity at the price to beat on January 1, 2004 less the number of new customers obtained by Reliant Resources outside Reliant Energy HL&P's service area. Amounts received from Reliant Resources with respect to the clawback payment, if any, will be included in the 2004 stranded cost true-up as a reduction of stranded costs. For additional information regarding this payment, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Reliant Resources — unregulated business — "clawback" Payment to Reliant Energy" in Item 7 of this Form 10-K. For discussion of the 2004 true-up proceedings, please read Note 4(a) to our consolidated financial statements.

The master separation agreement contains provisions relating to certain nuclear decommissioning assets, the exchange of information, provision of information for financial reporting purposes, dispute resolution, and provisions limiting competition between the parties in certain business activities and provisions allocating responsibility for the conduct of regulatory proceedings and limiting positions that may be taken in legislative, regulatory or court proceedings in which the interests of both parties may be affected. For additional information regarding the nuclear decommissioning assets, please read "Regulation — Nuclear Regulatory Commission" in Item 1 of this Form 10-K.

Texas Genco Option Agreement. Reliant Energy and Reliant Resources also entered into an agreement under which, subject to the completion of the Distribution, Reliant Resources will have an option to purchase all of the shares of capital stock of Texas Genco owned by CenterPoint Energy after the initial public offering or distribution of no more than 20% of Texas Genco's capital stock (Texas Genco Option). The Texas Genco Option may be exercised between January 10, 2004 and January 24, 2004. The per share exercise price under the option will be the average daily closing price on the national exchange for publicly held shares of common stock of Texas Genco for the 30 consecutive trading days with the highest average closing price during the 120 trading days immediately ending January 9, 2004, plus a control premium, up to a maximum of 10%, to the extent a control premium is included in the valuation determination made by the Texas Utility Commission relating to the market value of Texas Genco's common stock equity. The exercise price is also subject to adjustment based on the difference between the cash dividends paid during the period there is a public ownership interest in Texas Genco and Texas Genco's earnings during that period. For additional

information regarding recovery of stranded costs, please read "Regulation — State and Local Regulations — Texas — Electric Operations — Stranded Costs and Regulatory Assets" in Item 1 of this Form 10-K and Note 4(a) to our consolidated financial statements.

If Reliant Resources exercises the Texas Genco Option and purchases CenterPoint Energy's shares of Texas Genco common stock, Reliant Resources will also be required to purchase all notes and other receivables from Texas Genco then held by CenterPoint Energy, at their principal amount plus accrued interest. Similarly, if Texas Genco holds notes or receivables from CenterPoint Energy, Reliant Resources will assume those obligations in exchange for a payment to Reliant Resources by CenterPoint Energy of an amount equal to the principal plus accrued interest. If Reliant Resources does not exercise the Texas Genco Option, CenterPoint Energy may continue to operate Texas Genco or sell or otherwise dispose of its operations. If CenterPoint Energy continues to operate Texas Genco after 2005, it will need to replace or enter into a new arrangement for the provision of technical services for the operation of Texas Genco's facilities, which services are currently being provided by Reliant Resources under the technical services agreement, which is described below and expires upon Reliant Resources' purchase of Texas Genco shares if it exercises the Texas Genco Option or in 2005 if the Texas Genco Option is not exercised, subject to additional conditions.

The purchase of the shares of Texas Genco common stock upon exercise of the Texas Genco Option by Reliant Resources will be subject to various regulatory approvals, including Hart-Scott-Rodino antitrust clearance and United States Nuclear Regulatory Commission (NRC) license transfer approval.

Technical Services Agreement. Reliant Resources provides engineering and technical support services and environmental, safety and industrial health services to support operation and maintenance of the generation facilities to be transferred to Texas Genco under the technical services agreement. Reliant Resources also provides systems, technical, programming and consulting support services and hardware maintenance (but excluding plant-specific hardware) necessary to provide dispatch planning, dispatch and settlement and communication with the independent system operator, as well as general information technology services for the generation facilities to be transferred to Texas Genco. The fees Reliant Resources charges for these services allow it to recover its fully allocated direct and indirect costs and reimbursement of all out-of-pocket expenses. Expenses associated with capital investment in systems and software that benefit both the operation of the generation facilities to be transferred to Texas Genco and Reliant Resources' facilities in other regions are allocated on an installed megawatt basis.

Other Agreements. Reliant Energy and Reliant Resources entered into several other agreements pursuant to the master separation agreement. These agreements include an employee matters agreement, which addresses asset and liability allocation relating to Reliant Resources' employees and their continued participation in Reliant Energy's benefit plans, and a tax allocation agreement, which governs the allocation of U.S. income tax liabilities and sets forth agreements with respect to other tax matters. These agreements, along with the master separation agreement, the Texas Genco Option agreement and the technical services agreement, are filed as exhibits to this Form 10-K.

Common Directors on Reliant Resources' and Reliant Energy's Board of Directors and Stock Ownership of Management

Three of Reliant Energy's directors are also directors of Reliant Resources. One of these directors is Reliant Energy's chairman, president and chief executive officer. These directors owe fiduciary duties to the stockholders of each company. As a result, in connection with any transaction or other relationship involving both companies, these directors may need to recuse themselves and not participate in any board action relating to these transactions or relationships. It is anticipated that at the time of Distribution, one of these directors will resign as a director of Reliant Energy. In addition, members of Reliant Energy's board of directors and management own stock in Reliant Resources, and vice versa.

ELECTRIC OPERATIONS

General

Our Electric Operations business segment and the discussion in this section include only our electric utility operations that traditionally have been subject to regulation by the Texas Utility Commission and do not include operations in other states or operations in the state of Texas that are not regulated by the Texas Utility Commission. For information about our other power-related operations, please read "Wholesale Energy" in Item 1 of this Form 10-K. In 2001, Reliant Energy HL&P conducted our electric operations as a traditional integrated electric utility, including generation, transmission and distribution, and retail electric sales operations. Retail electric sales involve the sale of electricity and related services to end users of electricity, including industrial, commercial and residential customers. We generated, purchased for resale, transmitted, distributed and sold electricity to approximately 1.7 million customers in a 5,000-square mile area on the Texas Gulf Coast, including Houston, through the operations of this business segment.

As contemplated by the Texas Electric Restructuring Law, full retail competition began in Texas on January 1, 2002. In response to the Texas Electric Restructuring Law and as part of the Separation, we have functionally separated our generation, transmission and distribution operations and are in the process of separating those operations among different business entities. In December 2000, prior to the beginning of retail competition, we transferred our retail electric sales operations to subsidiaries of Reliant Resources, though our retail customers remained customers of Reliant Energy HL&P until their first meter reading following the onset of full retail competition on January 1, 2002. After that date those customers have been entitled to purchase their electricity from any of a number of certified retail electric providers, including Reliant Resources. Residential and small commercial customers who did not select another retail electric provider became customers of Reliant Resources, where the bulk of those customers have remained to date. For information about the retail operations we conduct through Reliant Resources, please read "Retail Energy" in Item 1 of this Form 10-K.

The generation operations in our Electric Operations business segment remained part of Reliant Energy HL&P throughout 2001, but are now operated independently of the retail electric sales and transmission and distribution operations. In this Form 10-K, we sometimes collectively refer to the generating facilities and operations to be transferred to Texas Genco in the Restructuring as our "Texas generation business." If Reliant Resources exercises the Texas Genco Option, the Texas Genco operations will cease to be part of our business in 2004. If Reliant Resources does not exercise the Texas Genco Option, we may continue to operate Texas Genco or dispose of its operations. For more information about the Texas Genco Option, please read "Reliant Energy's Relationship With Reliant Resources — Intercompany Agreements — Texas Genco Option Agreement" in Item 1 of this Form 10-K.

After the Restructuring, our transmission and distribution operations, which also were part of Reliant Energy HL&P throughout 2001, will comprise substantially all of the ongoing operations of the entity now known as Reliant Energy. As described above in "— Business Separation," that entity will become CenterPoint Houston, a limited liability company. In this Form 10-K, we refer to our transmission and distribution operations, operated since January 1, 2002, as a functionally separate unit by Reliant Energy and as they will be operated by CenterPoint Houston after the Restructuring, as the "T&D Utility."

ERCOT Market Framework

The state of Texas, other than a portion of the panhandle and a portion of the eastern part of the state bordering on Louisiana, constitutes a single reliability council (ERCOT market). On July 31, 2001, as part of the transition to deregulation in Texas, the Electric Reliability Council of Texas, Inc. (ERCOT) changed its operations from ten control areas, each managed by one of the utilities in the state, to a single control area managed by ERCOT. The ERCOT independent system operator (ERCOT ISO) is responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to anyone needing the information. It is also responsible for ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale

buyers and sellers in the ERCOT market. Unlike independent systems operators in other regions of the country, ERCOT is not a centrally dispatched power pool and the ERCOT ISO does not procure energy on behalf of its members other than to maintain the reliable operations of the transmission system. Members are responsible for contracting their energy requirements bilaterally. ERCOT also serves as agent for procuring ancillary services for those who elect not to provide their own ancillary service requirement.

Members of ERCOT include retail customers, investor and municipally owned electric utilities, rural electric co-operatives, river authorities, independent generators, power marketers and retail electric providers. The ERCOT market operates under the reliability standards set by the North American Electric Reliability Council. The Texas Utility Commission has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity across the state's main interconnected power grid. For information regarding ERCOT systems problems and delays, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations — Operational Risks" in Item 7 of this Form 10-K.

As part of the change to a single control area, ERCOT initially established three congestion zones: north, west and south. These congestion zones are determined by physical constraints on the ERCOT transmission system that make it difficult or impossible at times to move power from a zone on one side of the constraint to the zone on the other side of the constraint. ERCOT will perform an annual analysis of the transmission capability and constraints in ERCOT to determine if changes to the congestion zones are required. Any required changes will take effect January 1 of the following year. Such an analysis was performed in the fall of 2001 and as a result, ERCOT was reorganized into four congestion zones on January 1, 2002. The current zones are north, south, west and Houston. In addition, ERCOT conducts annual and monthly auctions of Transmission Congestion Rights (TCR) which provide the entity owning TCRs the ability to financially hedge price differences between zones (basis risk). Entities are currently limited to owning a maximum of 25% of the available TCRs. The transmission and distribution, generation and retail load that were formerly conducted under or served by Reliant Energy HL&P are predominately in the Houston zone. For additional information regarding these operations, please read "— Transmission and Distribution," and "— Generation" in Item 1 of this Form 10-K. For additional information regarding the retail load obligations of our Retail Energy business segment, please read "Retail Energy — Retail Energy Supply" in Item 1 of this Form 10-K.

Transmission and Distribution

All of the transmission and distribution operating properties in our Electric Operations business segment are located in the State of Texas. Our transmission system carries electricity from power plants to substations and from one substation to another. These substations serve to connect the power plants, the high voltage transmission lines and the lower voltage distribution lines. Unlike the transmission system, which carries high voltage electricity over long distances, distribution lines carry lower voltage power from the substation to customers. The distribution system consists of primary distribution lines, transformers, secondary distribution lines and service wires.

Under the Texas Electric Restructuring Law, our T&D Utility cannot buy or sell electricity (except for its own consumption) and thus is no longer subject to commodity risk. Rates for the T&D Utility will continue to be set by the Texas Utility Commission, and we will be allowed to provide services under approved tariffs. Pursuant to the Texas Electric Restructuring Law, the Texas Utility Commission issued an order (Docket No. 22355) setting rates for the T&D Utility, which became effective on January 1, 2002. In our appeal of certain aspects of the order, the Travis County District Court generally upheld the Texas Utility Commission's order. We may appeal the district court's decision in the Texas Court of Appeals, but have not yet filed such an appeal. For additional information regarding those rates, please read "Regulation — State and Local Regulations — Texas — Electric Operations — Rate Case" in Item 1 of this Form 10-K.

Historically, Reliant Energy HL&P paid the incorporated municipalities in its service territory a franchise fee based on a formula that was usually a percentage of revenues received from electricity sales for consumption within each municipality. Since January 1, 2002, the T&D Utility has become responsible for Reliant Energy HL&P's obligations under these franchise arrangements. Pursuant to the Texas Electric

Restructuring Law, the franchise fee payable by the T&D Utility to each municipality is based on the megawatt hours (MWh) delivered to customers within each municipality in 2002 and beyond. The amount per MWh payable by the T&D Utility is based on the franchise fees paid and the MWh consumed within each municipality in 1998. We expect the franchise fees payable by the T&D Utility to remain consistent with the fees paid by Reliant Energy HL&P; however, the new fees could be higher if electricity sales increase. The T&D Utility would be able to adjust its rates to recover such an increase only through a general T&D Utility rate case in which all of its expenses and revenues were subject to review.

Electric Lines — Overhead. As of December 31, 2001, we owned 25,998 pole miles of overhead distribution lines and 3,606 circuit miles of overhead transmission lines, including 452 circuit miles operated at 69,000 volts, 2,095 circuit miles operated at 138,000 volts and 1,059 circuit miles operated at 345,000 volts.

Electric Lines — Underground. As of December 31, 2001, we owned 12,701 circuit miles of underground distribution lines and 15.6 circuit miles of underground transmission lines, including 4.5 circuit miles operated at 69,000 volts and 11.1 circuit miles operated at 138,000 volts.

Substations. As of December 31, 2001, we owned 223 major substation sites (252 substations) having total installed rated transformer capacity of 64,783 megavolt amperes.

Generation

As of December 31, 2001, we owned and operated through our Texas generation business 12 power generating stations (62 generating units) with a net generating capacity of 14,095 megawatts (MW), including a 30.8% interest in the South Texas Project Electric Generating Station (South Texas Project). The South Texas Project is a nuclear generating station with two 1,250 MW nuclear generating units. For additional information regarding the South Texas Project, please read Note 6 to our consolidated financial statements. After the Restructuring, our Texas generation business will be owned by Texas Genco. Effective January 1, 2002, our Texas generation business will be reported separately as a new business segment, Electric Generation. Beginning January 1, 2002, our Texas generation business has been operated as an independent power producer, with output sold at market prices to a variety of purchasers, which include Reliant Resources and its subsidiaries. Because of this change, historical operating data, such as demand and fuel data, may not accurately reflect the operation of this business subsequent to December 31, 2001.

The Texas market currently has a surplus of generating capacity, which helps to facilitate a competitive wholesale market. Generators in ERCOT added 6,925 MW of new capacity in 2001. Due to the large quantity of generation built recently, it is anticipated that the wholesale market in Texas will be extremely competitive for the next three to five years.

The table below contains information regarding the system capability at peak demand of our generation facilities, which, during the periods shown, were dedicated to providing generation for Reliant Energy HL&P's service territory. Sales of electricity by our Electric Operations business segment during the summer months have generally been higher than sales during other months of the year due to the reliance on air conditioning by customers in Houston and in other parts of Reliant Energy HL&P's service territory.

Year	Installed Net Capability At Peak (MW)	Firm Purchased Power Contracts (MW)	Total Net Capability (MW)	Maximum Hourly Firm Demand		% Change From Prior Year	Calculated Reserve Margin (%)(3)
				Date	MW(1)(2)		
1997	13,960	445	14,405	August 21	12,246	4.7	17.6
1998	14,040	320	14,360	August 3	13,006	6.2	10.4
1999	14,052	320	14,372	August 20	13,053	0.4	10.1
2000	14,040	770(4)	14,810	September 5	14,569	11.6	1.7
2001	14,040	320	14,360	August 17	13,228	(9.2)	8.6

(1) Excludes loads on interruptible service tariffs, residential direct load control and commercial/industrial load cooperative capability. Including these loads, the maximum hourly demand served was 14,272 MW in 1998, 14,642 MW in 1999, 15,505 MW in 2000 and 14,210 MW in 2001.

(2) Maximum hourly firm demand in 1998 and 2000 was influenced by customer growth and hotter than normal weather at the time of the system peak. The extremely hot weather conditions at peak periods in Reliant Energy HL&P's service area during the summer of 2000 increased system peak load by approximately 1,100 MW.

(3) At any given time we have the ability to enter, and have entered, into non-firm contracts for purchased power on the spot market within ERCOT, to provide additional total capability. The addition of 6,925 MW of capacity in ERCOT in 2001, during which we experienced normal weather conditions, resulted in ERCOT reserve margins of 28%, significantly more than the 15% ERCOT minimum requirement. Although ERCOT historically has set operating reserve margins for its participants in the Texas market, ERCOT is in the process of reviewing its reserve margin protocols as a result of changes in the Texas market since the implementation of the Texas Electric Restructuring Law. In order to assure capacity to meet future demand requirements, both ERCOT and the Texas Utility Commission are reviewing procedures which would require market participants to provide adequate planning reserves.

(4) Includes 450 MW of firm capacity purchased to meet peak demand.

Facilities. The assets in our Texas generation business are described in the table below.

Generation Facilities	Net Generating Capacity as of December 31, 2001 (in MW)	Dispatch Type(1)	Primary/Secondary Fuel
W. A. Parish(2)	3,661	Base, Inter, Cyclic, Peak	Coal/Gas
Limestone(3)	1,532	Base	Lignite
South Texas Project(4)	770	Base	Nuclear
San Jacinto(5)	162	Inter	Gas
Cedar Bayou	2,260	Inter	Gas/Oil
P. H. Robinson	2,213	Inter	Gas
T. H. Wharton	1,254	Cyclic, Peak	Gas/Oil
S. R. Bertron	844	Cyclic, Peak	Gas/Oil
Greens Bayou	760	Cyclic, Peak	Gas/Oil
Webster	387	Cyclic, Peak	Gas
Deepwater	174	Cyclic, Peak	Gas
H. O. Clarke	78	Peak	Gas
Total	14,095		

(1) The designations "Base," "Inter," "Cyclic" and "Peak" indicate whether the units at the stations described are base-load, intermediate, cyclic or peaking units, respectively.

(2) The capacity of the W.A. Parish facility was uprated from 3,606 MW to 3,661 MW on November 1, 2001.

(3) The capacity of the Limestone facility was uprated from 1,532 MW to 1,612 MW on January 1, 2002.

(4) We own a 30.8% interest in the South Texas Project electric generating station, a nuclear generating plant consisting of two 1,250 MW generating units.

(5) This facility is a "cogeneration" facility. Please read the discussion below.

Power generation facilities can generally be categorized by their variable cost to produce electricity, which determines the order in which they are utilized to meet fluctuations in electricity demand. The largest component of variable cost is fuel cost. "Base-load" facilities are those that typically have low fuel costs to

generate electricity and provide power at all times. Base-load facilities are used to satisfy the base level of demand for power, or "load," that is not dependent upon time of day or weather. "Peaking" facilities generally have the highest fuel costs to generate electricity and typically are used only during periods of highest demand for power. "Intermediate" and "cyclic" facilities have cost and usage characteristics in between those of base-load and peaking facilities. Cyclic facilities generally operate with frequent starts and stops, and generally at lower efficiencies and higher operating costs than base-load plants. The various tiers of base-load, intermediate, cyclic and peaking facilities serving a particular region are often referred to as the "supply curve" or "dispatch curve" for that region. Power generation facilities can also be categorized as "cogeneration" facilities. Cogeneration is the combined production of steam and electricity in a generation facility. Cogeneration facilities typically operate at base load and higher thermal efficiency than other forms of fossil-fuel-fired generation facilities.

For information regarding the possible impairment for accounting purposes of these generating assets after the transition to market based rates and the recovery of these amounts, please read Notes 2(e) and 4(a) to our consolidated financial statements.

Market Framework. Historically, most power generation in Texas came from integrated utilities and was sold to retail customers at regulated rates. However, since 1996, independent power producers have been permitted to sell their entire load of electricity, capacity and ancillary services to wholesale purchasers at unregulated rates. Since January 1, 2002, any wholesale producer of electricity that qualifies as a "power generation company" under the Texas Electric Restructuring Law and that can access the ERCOT electric grid is allowed to sell power in the Texas market at unregulated rates. Transmission capacity, which may be limited, is needed to effect power sales. In the Texas market, buyers and sellers may negotiate bilateral wholesale capacity, energy and ancillary services contracts. Also, companies or business units whose power generation facilities were formerly part of integrated utilities, like our Texas generation business, must auction entitlements to 15% of their capacity as described below. Furthermore, buyers and sellers may participate in the spot market.

Operations and Capacity Auctions Generally. Since January 1, 2002, we have operated our Texas generation business solely in the wholesale market. We are required by the Texas Electric Restructuring Law to auction 15% of the capacity of our Texas generation business and by the master separation agreement to auction the remainder of the capacity of our Texas generation business. We may satisfy these capacity auction obligations either by producing electricity in our own power plants or by purchasing power in wholesale transactions. Our auction products are only entitlements to capacity dispatched from base, intermediate, cyclic or peaking units and do not convey a right to receive power from a particular unit. This enables us to dispatch our commitments in the most cost-effective manner, but also exposes us to the risk that, depending upon the availability of our units, we could be required to supply energy from a higher cost unit, such as an intermediate unit, to meet an obligation for lower cost generation, such as base-load generation or to obtain the energy on the open market. In addition, from time to time, we may be required to purchase power from qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA). For information about purchased power obligations, please read "— Fuel and Purchased Power — Purchased Power Supply" in Item 1 of this Form 10-K.

Revenues from capacity auctions come from two sources: capacity payments and fuel payments. Capacity payments are based on the final clearing prices, in dollars per kilowatt-month, determined during the auctions. We bill for these payments on a monthly basis just prior to the month of the entitlement. Fuel payments consist of a variety of charges related to the fuel and ancillary services scheduled through the auctioned products. We invoice for these fuel payments on a monthly basis in arrears. Please read "— Fuel and Purchased Power" in Item 1 of this Form 10-K.

State Mandated Capacity Auctions. Under the Texas Electric Restructuring Law, each power generator that is unbundled from an integrated electric utility in Texas, including our Texas generation business, is required to sell at auction 15% of the output of its installed generating capacity (state mandated auctions). This obligation to conduct state mandated auctions will continue until January 1, 2007, unless before that date the Texas Utility Commission determines that at least 40% of the electric power consumed before the onset of

competition by residential and small commercial customers in the T&D Utility's service area is being served by retail electric providers not affiliated or formerly affiliated with us as an integrated utility. The Texas Utility Commission has determined Reliant Resources is our affiliate and will be an affiliate of Texas Genco for this purpose. Reliant Resources is not permitted under the Texas Electric Restructuring Law to purchase capacity sold by us or by Texas Genco in the state mandated auctions.

The products we are, and Texas Genco will be, required to offer in the state mandated auctions are determined by rules adopted by the Texas Utility Commission. The aggregate products sold under the state mandated auctions consist of 700 MW of base-load, 875 MW of intermediate, 400 MW of cyclic and 150 MW of peaking capacity. These products are sold in the form of "entitlements," which consist of obligations to provide 25 MW of capacity for terms of one month, one year and two years. Texas Utility Commission rules require 50% of available auctioned products to consist of one-month entitlements, 30% to consist of one-year strips and 20% to consist of two-year strips. Purchasers of products offered in the state mandated auctions may resell them to third parties other than an affiliated retail electric provider.

Contractually Mandated Capacity Auctions. Pursuant to the master separation agreement, and subject to the permitted reductions described below, we are, and Texas Genco will be, contractually obligated to auction to third parties, including Reliant Resources, all of the capacity and related ancillary services available in excess of amounts included in the state mandated auctions until the date on which the Texas Genco Option either is exercised or expires (contractually mandated auctions). We and Texas Genco are permitted to reduce the amount of capacity sold in the contractually mandated auctions by the amount required to satisfy:

- our operational requirements associated with the capacity sold pursuant to the Texas Utility Commission rules, including the rules associated with state mandated auctions and the price to beat; or
- our obligations to another party under an existing spinning reserve service agreement.

Texas Utility Commission rules do not restrict the types of products we and Texas Genco may offer in the contractually mandated auctions. Therefore, we set the terms of the products offered in these auctions. We structure the products in the contractually mandated auctions to correspond with operating characteristics of the underlying generating units, such as heat rates and minimum load levels. Pursuant to the master separation agreement, Reliant Resources is entitled to purchase, prior to our submission of capacity to auction, 50% (but not less than 50%) of the capacity we have available to auction in the contractually mandated auctions at the prices bid by third parties in the contractually mandated auctions. Whether or not Reliant Resources exercises this right, Reliant Resources may submit bids to purchase in the contractually mandated auctions as well.

Initial Auctions. We conducted state mandated auctions in September 2001 and March 2002 and contractually mandated auctions in October and December 2001 and March 2002. Excluding reserves for planned and forced outages, as a result of these auctions, our Texas generation business has sold entitlements to all of its capacity through August 2002, an average of 72% per month of its capacity through December 2002 and 10% of its capacity for each month in 2003. In the contractually mandated auctions held so far, Reliant Resources has purchased, on average, 72% per month of the 2002 capacity sold by us and 58% per month of our 2003 capacity sold in the auctions. These purchases have been made either through the exercise by Reliant Resources of its contractual rights or through the submission of bids.

The capacity auctions were consummated at market-based prices that are substantially below the historical regulated return on the facilities in our Texas generation business. The Texas Electric Restructuring Law provides for the recovery in a "true-up" proceeding of any difference between market power prices received in the capacity auctions and the Texas Utility Commission's earlier estimates of those market prices. For additional information regarding the capacity auctions and the related true-up proceeding, please read Note 4 to our consolidated financial statements.

We intend to conduct an auction in July 2002 to sell the remaining available capacity for September through December 2002. Beginning in September 2002, we intend to hold auctions to sell remaining capacity for the year 2003.

Fuel and Purchased Power

We rely primarily on natural gas, coal and lignite to fuel the facilities in our Texas generation business. For information regarding our fuel contracts, please read Note 14(a) to our consolidated financial statements. The 2000 and 2001 historical energy mix for our Texas generation business is set forth below. These figures represent the generation and purchased power used to meet system load and for off-system sales:

	Historical Energy Mix(%)	
	2000	2001
Natural gas	37	25
Coal and lignite	35	32
Nuclear	8	8
Purchased power	20	35
Total	100	100

As a result of new air emissions standards imposed by federal and state law, we anticipate longer plant outages in 2002 and higher levels of plant maintenance in 2003 and subsequent years associated with the installation of environmental equipment on our generating facilities. These factors could affect the fuel mix of our Texas generation business. We anticipate that the capital investment incurred through May 2003 to comply with these air emissions requirements will be recoverable through the Texas Utility Commission's determination of stranded costs. Please read "— Environmental Matters" in Item 1 of this Form 10-K and Note 4 to our consolidated financial statements.

Through December 31, 2001, the Texas Utility Commission provided for the recovery of most fuel and purchased power costs from customers through a fixed fuel factor included in electric rates. Following the transition to retail competition in January 2002, the energy sales of our Texas generation business are based on the generation capacity entitlement auctions described above. Power generated from the intermediate, cyclic or peaking entitlements in the capacity auctions includes a fuel cost component that is tied to the indexed cost of gas, reducing the risk associated with the price of gas for our Texas generation business. Successful bidders in these auctions are able to dispatch energy from their entitlements within the operational constraints of the generating units supporting the capacity entitlement product they purchased. Under the terms of the capacity auctions, successful bidders are required to absorb the corresponding fuel cost for the energy dispatched so that, in effect, we will recover our dispatch-based fuel costs from these bidders. For additional information regarding our ability to recover these costs from customers before and after the inception of retail electric competition, please read "Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" in Item 1 of this Form 10-K and Note 4(a) to our consolidated financial statements.

Natural Gas Supply. We obtain our long-term natural gas supply under contracts with El Paso Merchant Energy-Gas L.P., HPL Resources Company and Kinder Morgan Texas Pipeline, Inc. Our contract with Kinder Morgan is nearing the end of its term and we are in the process of negotiating another long-term contract with them, which we expect to sign in the second quarter of 2002. Substantially all of our long-term natural gas supply contracts contain pricing provisions based on fluctuating spot market prices. In 2001, 61% of the natural gas requirements for our Texas generation business was purchased under these long-term contracts, including 34% under the contract with Kinder Morgan. The remaining 39% of natural gas requirements in 2001 was purchased on the spot market. Based on current market conditions, we believe we will be able to replace the supplies of natural gas covered under our long-term contracts when they expire with gas purchased on the spot market or under new long-term or short-term contracts if we continue to own Texas

Genco after 2004. The natural gas consumption and cost information for our Texas generation business in the year 2001 was as follows:

2001 average daily consumption	535	Bbtu (1)
2001 peak daily consumption	1,282	Bbtu
Average cost of natural gas	$ 4.23	per MMBtu (2)

(1) Billion British thermal units (Bbtu).

(2) Compared to $3.98 per million British thermal units (MMBtu) in 2000 and $2.47 per MMBtu in 1999.

Our natural gas requirements are generally more volatile than our other fuel requirements because we use natural gas to fuel intermediate, cyclic and peaking facilities and other more economical fuels to fuel base-load facilities. Although natural gas supplies have been sufficient in recent years, available supplies are subject to potential disruption due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time or prices may increase rapidly in response to temporary supply constraints or other factors. In 2001, prices for natural gas became more volatile due to market conditions.

Coal and Lignite Supply. We purchased approximately 80% of the fuel requirements for our four coal-fired generating units at our W.A. Parish facility under two fixed-quantity, long-term supply contracts with Kennecott Energy. Kennecott Energy supplies subbituminous coal under these contracts from mines in the Powder River Basin of Wyoming. The first of these contracts is scheduled to expire in 2010, and the second is scheduled to expire in 2011. The price for coal is fixed under one of these contracts through the end of 2002, after which the price will be tied to spot market prices. The price for coal under the second contract was approximately three times greater than the spot market prices for coal as of December 31, 2001. We purchased our remaining coal requirements for the W.A. Parish facility under short-term contracts. We have long-term rail transportation contracts with the Burlington Northern Santa Fe Railroad Company and the Union Pacific Railroad Company to transport coal to the W.A. Parish facility.

We obtain the lignite used to fuel the two generating units of the Limestone facility from a surface mine adjacent to the facility. We own the mining equipment and facilities and a portion of the lignite reserves located at the mine. During the first six months of 2002, we will obtain our lignite requirements under a long-term, cost-plus agreement with Westmoreland Coal Company. We expect to blend petroleum coke with lignite to fuel the Limestone facility in this period. Beginning July 2002, we will obtain our lignite requirements under an agreement with Westmoreland Coal Company at a fixed price determined annually that results in a cost of generation at the Limestone facility equivalent to the cost of generating with Wyoming coal. We expect the lignite reserves will be sufficient to provide all of the lignite requirements of this facility through 2015.

During 2000, we conducted a successful test burn of Wyoming coal at the Limestone facility. We anticipate using a blend of lignite and Wyoming coal to fuel the Limestone facility beginning in July 2002 as a component of our nitrogen oxides (NOx) control strategy. A fuel unloading and handling system is being installed at the Limestone facility to accommodate the delivery of Wyoming coal. We expect to obtain Wyoming coal and rail transportation services through spot and long-term market-priced contracts.

Nuclear Fuel Supply. The South Texas Project satisfies its fuel supply requirements by acquiring uranium concentrates, converting uranium concentrates into uranium hexafluoride, enriching uranium hexafluoride and fabricating nuclear fuel assemblies.

We are a party to numerous contracts covering a portion of nuclear fuel needs of the South Texas Project for uranium, conversion services, enrichment services and fuel fabrication. Other than a fuel fabrication agreement that extends for the life of the South Texas Project plant, these contracts have varying expiration dates, and most are short to medium term (less than seven years). Management believes that sufficient capacity for nuclear fuel supplies and processing exists to permit normal operations of the South Texas Project's nuclear generating units.

Purchased Power Supply. Prior to January 1, 2002, Reliant Energy HL&P purchased power from various qualifying facilities exercising their rights under PURPA. These purchases were generally at the discretion of the qualifying facilities and were made pursuant to a pricing methodology defined in tariffs approved by the Texas Utility Commission and pursuant to agreements between Reliant Energy HL&P and the qualifying facilities. Reliant Energy HL&P purchased a total of 16.4 million MWh and 19 million MWh from qualifying facilities in 2000 and 2001, respectively. Reliant Energy HL&P terminated all but two of its agreements with the qualifying facilities in 2001 pursuant to the terms of the agreements. The remaining two agreements expire March 31, 2005. The rights and obligations under the two remaining agreements will be assigned to Texas Genco in the Restructuring if they are not assigned to third parties.

As a result of the separation of Reliant Energy HL&P's utility functions, the T&D Utility will not be subject to PURPA and the Texas Utility Commission-approved tariffs in place before January 1, 2002 will no longer be effective. However, our Texas generation business and the retail electric providers under Reliant Resources will remain subject to PURPA. On January 23, 2002, certain qualifying facilities, including qualifying facilities that have traditionally delivered power to Reliant Energy HL&P, filed an enforcement action with the Federal Energy Regulatory Commission (FERC) seeking to force the Texas Utility Commission to implement PURPA for Texas entities subject to PURPA (FERC Docket No. EL02-55). On February 15, 2002, FERC filed notice of its intention not to act on this enforcement action. These qualifying facilities have the right to appeal this decision in federal court. In the meantime, the Texas Utility Commission is in the midst of a rulemaking proceeding to determine whether it has the authority to regulate the PURPA obligations of any entity and, if so, how such entity will implement its obligations, including a methodology for pricing of these purchases. We anticipate that this rulemaking will conclude in the second quarter of 2002. The proposed rule published by the Texas Utility Commission does not apply to Texas generation businesses. If the final rule is the same in this respect, our Texas generation business will self-implement its PURPA obligations and will not be required to seek approval of its pricing methodology from the Texas Utility Commission.

Competition

The T&D Utility's operations are regulated by the Texas Utility Commission and are conducted within its service territory pursuant to a Certificate of Convenience and Necessity issued by the Texas Utility Commission. In order for another provider of transmission and distribution services to provide such services in the T&D Utility's territory, it would be required to obtain a Certificate of Convenience and Necessity in proceedings before the Texas Utility Commission. Our Texas generation business competes with other power generation companies, including the now-unregulated generating facilities of other electric utilities, independent power producers who own generation facilities for the purpose of selling power in wholesale markets and power produced by cogenerators and other qualified facilities. Due to the large quantity of generation built recently in ERCOT, it is anticipated that the wholesale power market in Texas in which our Texas generation business competes will be extremely competitive for the next three to five years.

Please read "Electric Operations — ERCOT Market Framework" in Item 1 of this Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Electric Operations" in Item 7 of this Form 10-K, which sections are incorporated herein by reference.

NATURAL GAS DISTRIBUTION

Our Natural Gas Distribution business segment consists of intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas and some non-rate regulated retail gas marketing operations.

We conduct intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers through three unincorporated divisions of RERC Corp.: Arkla, Entex and Minnegasco. These operations are regulated as gas utility operations in the jurisdictions served by these divisions.

- *Arkla.* Arkla provides natural gas distribution services in over 245 communities in Arkansas, Louisiana, Oklahoma and Texas. The largest metropolitan areas served by Arkla are Little Rock, Arkansas and Shreveport, Louisiana. In 2001, approximately 65% of Arkla's total throughput was attributable to retail sales of gas and approximately 35% was attributable to transportation services.
- *Entex.* Entex provides natural gas distribution services in over 500 communities in Louisiana, Mississippi and Texas. The largest metropolitan area served by Entex is Houston, Texas. In 2001, approximately 97% of Entex's total throughput was attributable to retail sales of gas and approximately 3% was attributable to transportation services.
- *Minnegasco.* Minnegasco provides natural gas distribution services in over 240 communities in Minnesota. The largest metropolitan area served by Minnegasco is Minneapolis, Minnesota. In 2001, approximately 97% of Minnegasco's total throughput was attributable to retail sales of gas and approximately 3% was attributable to transportation services.

The demand for intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers is seasonal. In 2001, approximately 62% of our Natural Gas Distribution business segment's total throughput occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during those periods. For information about our plan to separate the operations of Arkla, Entex and Minnegasco among different business entities, please read "Our Business — RERC Corp. Restructuring" in Item 1 of this Form 10-K.

Commercial and Industrial Marketing Sales

Our Natural Gas Distribution business segment's commercial and industrial marketing sales group provides comprehensive natural gas products and services to commercial and industrial customers in the region from Southern Texas to the panhandle of Florida, as well as in the Midwestern United States. In 2001, approximately 96% of total throughput was attributable to the sale of natural gas and approximately 4% was attributable to transportation services. Typical customer contract terms for natural gas sales range from one day to three years. Our commercial and industrial marketing sales groups' operations may be affected by seasonal weather changes and the relative price of natural gas. In 2000, the commercial and industrial marketing sales group exited all retail gas markets in non-strategic areas of the Northeast and Mid-Atlantic, allowing us to focus resources and efforts in our core geographical areas of the Gulf South and Midwest.

Supply and Transportation

Arkla. In 2001, Arkla purchased approximately 53% of its natural gas supply from Reliant Energy Services, 29% pursuant to third-party contracts, with terms varying from three months to one year, and 18% on the spot market. Arkla's major third-party natural gas suppliers in 2001 included Oneok Gas Marketing Company, Tenaska Marketing Ventures, Marathon Oil Company and BP Energy Company. Arkla transports substantially all of its natural gas supplies under contracts with our pipeline subsidiaries.

Entex. In 2001, Entex purchased virtually all of its natural gas supply pursuant to term contracts, with terms varying from one to five years. Entex's major third-party natural gas suppliers in 2001 included AEP Houston Pipeline, Kinder Morgan Texas Pipeline, L.P., Gulf Energy Marketing, Island Fuel Trading and Koch Energy Trading. Entex transports its natural gas supplies on both interstate and intrastate pipelines under long-term contracts with terms varying from one to five years.

Minnegasco. In 2001, Minnegasco purchased approximately 74% of its natural gas supply pursuant to term contracts, with terms varying from one to ten years, with more than 20 different suppliers. Minnegasco purchased the remaining 26% on the daily or spot market. Most of the natural gas volumes under long-term contracts are committed under terms providing for delivery during the winter heating season, which extends from November through March. Minnegasco purchased approximately 67% of its natural gas requirements from four suppliers in 2001: Tenaska Marketing Ventures, Reliant Energy Services, Pan-Alberta Gas Ltd., and TransCanada Gas Services Inc. Minnegasco transports its natural gas supplies on various interstate pipelines under long-term contracts with terms varying from one to five years.

For additional information regarding our ability to pass through changes in natural gas prices to our customers, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Competitive and Other Factors Affecting RERC Operations — Natural Gas Distribution" in Item 7 of this Form 10-K.

Arkla and Minnegasco use various leased or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. Minnegasco also supplements contracted supplies and storage from time to time with stored liquefied natural gas and propane-air plant production.

Minnegasco owns and operates a 7.0 billion cubic feet (Bcf) underground storage facility, having a working capacity of 2.1 Bcf available for use during a normal heating season and a maximum daily withdrawal rate of 50 million cubic feet (MMcf) per day. Minnegasco also owns ten propane-air plants with a total capacity of 191 MMcf per day and on-site storage facilities for 11 million gallons of propane (1.0 Bcf gas equivalent). Minnegasco owns a liquefied natural gas facility with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf gas equivalent) with a send-out capability of 72 MMcf per day.

Although available natural gas supplies have exceeded demand for several years, currently supply and demand appear to be more balanced. Our Natural Gas Distribution business segment has sufficient supplies and pipeline capacity under contract to meet its firm customer requirements. However, from time to time, it is possible for limited service disruptions to occur due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time or prices may increase rapidly in response to temporary supply constraints or other factors.

Assets

As of December 31, 2001, we owned approximately 61,000 linear miles of gas distribution mains, varying in size from one-half inch to 24 inches in diameter. Generally, in each of the cities, towns and rural areas served by our Natural Gas Distribution business segment, we own the underground gas mains and service lines, metering and regulating equipment located on customers' premises and the district regulating equipment necessary for pressure maintenance. With a few exceptions, the measuring stations at which we receive gas from our suppliers are owned, operated and maintained by others, and our distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on the land owned by suppliers.

Competition

Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Competitive and Other Factors Affecting RERC Operations — Natural Gas Distribution" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

PIPELINES AND GATHERING

Our Pipelines and Gathering business segment operates two interstate natural gas pipelines as well as gas gathering and pipeline services. Our pipeline operations are primarily conducted by two wholly owned interstate pipeline subsidiaries of RERC Corp., Reliant Energy Gas Transmission Company (REGT) and Mississippi River Transmission Corporation (MRT). Our gathering and pipeline services operations are conducted by a wholly owned gas gathering subsidiary, Reliant Energy Field Services, Inc. (REFS), and a wholly owned pipeline services subsidiary, Reliant Energy Pipeline Services, Inc. (REPS).

Through REFS, we provide natural gas gathering and related services, including related liquids extraction and other well operating services. As of December 31, 2001, REFS operated approximately 4,300 miles of gathering pipelines, which collect natural gas from more than 300 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas. Through REPS, we provide pipeline project management and facility operation services to affiliates and third parties.

In 2001, approximately 25% of our Pipelines and Gathering business segment's total operating revenue was attributable to services provided by REGT to Arkla, and approximately 10% of its total operating revenue was attributable to services provided by MRT to Laclede Gas Company (Laclede), an unaffiliated distribution company that provides natural gas utility service to the greater St. Louis metropolitan area in Illinois and Missouri. An additional 20% of our Pipelines and Gathering business segment's operating revenues was attributable to the transportation of gas marketed by Reliant Energy Services. Our Pipelines and Gathering business segment provides service to Arkla and Laclede under several long-term firm storage and transportation agreements. REGT and Arkla have entered into various contracts for firm transportation in Arkla's major service areas that are currently scheduled to expire in 2005. In February 2002, MRT negotiated an agreement to extend its existing service relationship with Laclede for a five-year period subject to acceptance by the FERC.

The business and operations of our Pipelines and Gathering business segment may be affected by seasonal changes in the demand for natural gas, the relative price of natural gas in the Midcontinent and Gulf Coast natural gas supply regions and, to a lesser extent, general economic conditions.

Assets

We own and operate approximately 8,100 miles of gas transmission lines. We also own and operate six natural gas storage fields with a combined daily deliverability of approximately 1.2 Bcf per day and a combined working gas capacity of approximately 55.8 Bcf. REGT also owns a 10% interest, with Gulf South Pipeline Company, LP, in the Bistineau storage facility with 68.8 Bcf of working gas capacity and 1.1 Bcf per day of deliverability. REGT's storage capacity in the Bistineau facility is 18 Bcf (8 Bcf of working gas) with 100 MMcf per day of deliverability. Most of our storage operations are in north Louisiana and Oklahoma. We also own and operate approximately 4,300 miles of gathering pipelines that collect gas from more than 300 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Competition

Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors affecting Our Future Earnings — Competitive and Other Factors Affecting RERC Operations — Pipelines and Gathering" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

WHOLESALE ENERGY

Our Wholesale Energy business segment, which is conducted through Reliant Resources, provides energy and energy services with a focus on the competitive wholesale segment of the United States energy industry. We acquire, develop and operate electric power generation facilities that are not subject to traditional cost-based regulation and therefore can generally sell power at prices determined by the market, subject to regulatory limitations in certain regions. We also trade and market power, natural gas, natural gas transportation capacity and other energy-related commodities and provide related risk management services. Our Wholesale Energy business segment will remain with Reliant Resources in the Separation and will not be part of our business after the Distribution.

Power Generation Operations

As of December 31, 2001, our Wholesale Energy business segment owned or leased electric power generation facilities with an aggregate net generating capacity of 11,109 MW located in five regions of the United States. We also had 3,587 MW (3,391 MW, net of 196 MW to be retired upon completion of one facility) of net generating capacity under construction as of that date. In addition, by acquiring Orion Power Holdings, Inc. (Orion Power) in February 2002, we added 81 power plants with an aggregate net generating capacity of 5,644 MW and two development projects with an additional 804 MW of capacity under construction to our regional portfolios.

The following table describes our Wholesale Energy business segment's electric power generation facilities by region as of December 31, 2001.

Regional Summary of Our Generation Facilities
(As of December 31, 2001)

Region	Number of Generation Facilities(1)	Total Net Generating Capacity (MW)	Dispatch Type(2)	Fuel Type
Northeast				
Operating(3)	21	4,262	Base, Inter, Peak	Gas/Coal/Oil/Hydro
Under Construction(4)(5)(6)	1	1,120	Base, Inter, Peak	Gas/Oil/Coal
Combined	22	5,382		
Midwest				
Operating	2	1,063	Peak	Gas
Under Construction(7)	—	154	Peak	Gas
Combined	2	1,217		
Southeast				
Operating(8)	3	979	Inter, Peak, CoGen	Gas/Oil
Under Construction(5)(9)	1	958	Base, Inter, Peak	Gas/Oil
Combined	4	1,937		
West				
Operating(7)	7	4,635	Base, Inter, Peak	Gas
Under Construction	1	548	Base, Peak	Gas
Combined	8	5,183		
ERCOT(10)				
Operating	1	170	Base, CoGen	Gas
Under Construction(4)	—	611	Base, CoGen	Gas
Combined	1	781		
Total				
Operating	34	11,109		
Under Construction	3	3,391		
Combined	37	14,500		

(1) Unless otherwise indicated, we own a 100% interest in each facility listed.

(2) We use the designations "Base," "Inter," "Peak" and "CoGen" to indicate whether the facilities described are base-load, intermediate, peaking or cogeneration facilities, respectively.

(3) We lease a 100%, 16.67% and 16.45% interest in three Pennsylvania facilities having 613 MW, 285 MW and 281 MW, respectively, through facility lease agreements having terms of 26.5 years, 33.75 years and 33.75 years, respectively.

(4) One of our two construction projects in this region will replace one of our existing facilities upon completion. Therefore, this project is not included in the facility count for the "Under Construction" group of this region.

(5) Our two construction projects in the Northeast region and one of our projects in the Southeast region are owned by off-balance sheet special purpose entities and are being constructed under construction agency agreements pursuant to synthetic leasing arrangements. We expect that we will lease these facilities from their owners upon completion.

(6) The 1,120 MW of net capacity under construction is based on 1,316 MW of capacity currently under construction less 196 MW of operating capacity that will be retired upon completion of one of the projects.

(7) Five of the six generating units of one of the facilities in this region are operational while the sixth unit is under construction. This partially operational facility is included in the facility count for the "Operating" group of this region.

(8) We own a 50% interest in one of these facilities. An independent third party owns the other 50%.

(9) Two of the three generating units of one of the facilities in this region are operational while the third unit is under construction. This partially operational facility is included in the facility count for the "Operating" group of this region.

(10) For information about the Texas Genco Option, please read "Reliant Energy's Relationship with Reliant Resources — Intercompany Agreements — Texas Genco Option Agreement" in Item 1 of this Form 10-K and Note 4(b) to our consolidated financial statements.

The following table describes our Orion Power electric power generation facilities by region as of February 28, 2002.

Regional Summary of Our Orion Power Facilities
(As of February 28, 2002)

Region	Number of Generation Facilities	Total Net Generating Capacity (MW)	Dispatch Type(1)	Fuel Type
Northeast				
Operating(2)	78	4,174	Base, Inter, Peak	Gas/Oil/Coal/Hydro
Under Construction	2	804	Base, Inter	Gas
Combined	80	4,978		
Midwest				
Operating	3	1,470	Base, Inter, Peak	Coal/Gas
Total				
Operating(2)	81	5,644		
Under Construction	2	804		
Combined(2)	83	6,448		

(1) We use the designations "Base," "Inter" and "Peak" to indicate whether the facilities described are base-load, intermediate or peaking, respectively.

(2) Two hydro plants with a net generating capacity of approximately 5 MW are not currently operational.

Northeast Region

Facilities. As of December 31, 2001, we owned or leased 21 electric power generation facilities with an aggregate net generating capacity of 4,262 MW located in the control area of PJM Interconnection, L.L.C. (PJM ISO), the independent system operator in the Pennsylvania-New Jersey-Maryland market (PJM market). These facilities are owned or leased by subsidiaries of Reliant Energy Mid-Atlantic Power Holdings, LLC (REMA), a wholly owned subsidiary of Reliant Resources. The generating capacity of these facilities consists of approximately 40% of base-load, 40% of intermediate and 20% of peaking capacity, and represents approximately 7% of the total generation capacity located in the PJM ISO's control area. For additional information regarding our acquisition of these facilities, please read Note 3(a) to our consolidated financial statements.

By acquiring Orion Power in February 2002, we added 78 power generation facilities, of which 75 are currently operational, with an aggregate net generating capacity of 4,174 MW to our Northeast regional

portfolio. These facilities include 70 hydroelectric facilities, of which 68 are currently operational, located in central and northern New York State, three facilities located in New York City, one facility located in East Syracuse, New York, and four facilities, three of which are currently fully operational, located in Pennsylvania. The generating capacity of these facilities consists of approximately 45% of base-load, 35% of intermediate and 20% of peaking capacity. For a discussion of factors that may affect the future earnings generated by these Orion Power facilities, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Integration and Other Risks Associated With Our Orion Power Assets" and "— Uncertainty Related to the New York Regulatory Environment" in Item 7 of this Form 10-K.

We have begun construction on a 795 MW gas-fired base-load and intermediate facility located in Pennsylvania. We expect this facility will begin commercial operation in the second quarter of 2003. We have also begun construction on a 521 MW coal-fired base-load facility, also located in Pennsylvania, that will replace one of our existing facilities. This facility will add 325 MW of additional capacity to our Northeast regional portfolio, net of the 196 MW of capacity of the currently existing facility that will be retired upon commencement of commercial operations of the new facility. We expect this facility will begin commercial operation near the end of 2004. These facilities are owned by off-balance sheet special purpose entities and are being constructed under the terms of separate construction agency agreements pursuant to synthetic leasing arrangements. Upon completion of the construction of these facilities, we expect that we will lease these facilities from their owners, purchase or remarket each facility. For additional information regarding the construction agency agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Sources and Uses of Cash — Reliant Resources-unregulated businesses — Consolidated Sources of Cash — Off-Balance Sheet Transactions — Construction Agency Agreements" in Item 7 of this Form 10-K and Note 14(l) to our consolidated financial statements.

By acquiring Orion Power in February 2002, we added two additional development projects with an additional 804 MW of capacity under construction. The first project is the construction of a 550 MW gas-fired base-load facility located south of Philadelphia, Pennsylvania. We expect this facility will begin commercial operation in the second quarter of 2002. The second project is the conversion and upgrade of a peaking facility located near downtown Pittsburgh, Pennsylvania. We expect this project will be completed by the third quarter of 2002 and will increase the aggregate generating capacity of this facility by 254 MW to a total capacity of 308 MW.

Market Framework. We currently sell the power generated by our Northeast regional facilities in the PJM market, the wholesale energy market of the State of New York (New York wholesale market) operated by the New York Independent System Operator (NYISO) and to buyers in adjacent power markets, such as the region covered by the East Central Area Reliability Coordinating Counsel (ECAR market). We also expect to sell power in a newly created extension of the PJM market in western Pennsylvania (PJM West market). Each of the PJM Market, the New York wholesale market and the PJM West market operate as centralized power pools with open-access, non-discriminatory transmission systems administered by independent system operators approved by the FERC. Although the transmission infrastructure within these markets is generally well developed and independently operated, transmission constraints exist between, and to a certain extent within, these markets. In particular, transmission of power from eastern Pennsylvania to western Pennsylvania and into New York City may be constrained from time to time. Depending on the timing and nature of transmission constraints, market prices may vary from market to market, or between sub-regions of a particular market. For example, as a result of transmission constraints into New York City, power prices are generally higher there than in other parts of the state.

In addition to managing the transmission system for each market, the respective independent system operator for each of the PJM market, the New York wholesale market and the PJM West market is responsible for maintaining competitive wholesale markets, operating the spot wholesale energy market and determining the market clearing price based on bids submitted by participating generators in each market. Each independent system operator generally matches sellers with buyers within a particular market that meet

specified minimum credit standards. We sell capacity, energy and ancillary services into the markets maintained by the applicable independent system operator for each of these types of products for both real-time sales and forward-sales for periods of up to one year. Our customers include the members of each market, consisting of municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities, retail electric providers and power marketers. We also sell capacity, energy and ancillary services to customers in the Northeast region under negotiated bilateral contracts. Bilateral contracts, in addition to other physical and financial transactions enable us to hedge a portion of our generation portfolio. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generating assets (other than those in our Texas generation business, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

Our markets in the Northeast region are subject to constant and significant regulatory oversight and control and the results of our operations in the region may be adversely affected by any changes or additions to the current regulatory structure. Our sales into markets administered by the PJM ISO are governed by the PJM ISO's operating agreements, tariffs and protocols (PJM Protocols). The PJM Protocols provide the structure, rules and pricing mechanisms for the PJM ISO's energy, capacity and ancillary services markets, and establish rates, terms and conditions for transmission service in the PJM ISO's control area and the PJM West market, including transmission congestion pricing. Wholesale energy prices in the markets administered by the PJM ISO are currently capped at $1,000 per megawatt-hour. Lower caps are utilized in other regions and it is possible that this price cap might be lowered in the future.

Our sales into markets administered by the NYISO are governed by the NYISO's tariff and protocols (NYISO Protocols). The NYISO Protocols provide the structure, rules and pricing mechanisms for the NYISO's energy, capacity and ancillary services markets, and establish rates, terms and conditions for transmission service in the NYISO's control area. The NYISO Protocols allow load to respond to high prices in emergency and non-emergency situations. The lack of programs, however, to implement load response to prices has been cited as one of the primary reasons for retaining wholesale energy bid caps, which are currently set at $1,000 per megawatt-hour. Lower price caps are utilized in other regions and it is possible that this price cap might be lowered in the future.

A capacity market has been established by the NYISO that ensures that there is enough generation capacity to meet retail energy demand and ancillary services requirements. All power retailers are required to demonstrate commitments for capacity sufficient to meet their peak forecasted load plus a reserve requirement, currently set at 18%. As an extra reliability measure, power retailers located in New York City are required to procure the majority of this capacity, currently 80% of their peak forecasted load, from generating units located in New York City. Because New York City is currently short of this capacity requirement and the existing capacity is owned by only a few entities, a price cap has been instituted for in-city generators.

For additional discussion of the impact of current regulations on the markets in the Northeast region and the related risks of re-regulation, please read "— Regulation — Federal Energy Regulatory Commission" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Industry Restructuring, the Risk of Re-regulation and the Impact of Current Regulations" and "— Uncertainty Related to the New York Regulatory Environment" in Item 7 of this Form 10-K.

Midwest Region

Facilities. As of December 31, 2001, we owned two electric power generation facilities located in the State of Illinois with an aggregate net generating capacity of 1,063 MW in operation. One of these facilities is a 344 MW gas-fired peaking generation facility located in Shelby County, Illinois. The first phase of this facility was initially placed in commercial operation in June 2000 and the second phase was placed in commercial operation in May 2001. We also have an 873 MW gas-fired peaking generation facility under construction in Aurora, Illinois. As of December 31, 2001, five of the six generating units at this facility with

an aggregate net generating capacity of 719 MW had been placed in commercial operation. We expect the remaining unit at this facility will begin commercial operation in the second quarter of 2002.

By acquiring Orion Power in February 2002, we added three power generation facilities with an aggregate net generating capacity of 1,470 MW to our Midwest regional portfolio. Two of these facilities are located in Ohio and one is located in West Virginia. The generating capacity of these facilities consists of approximately 50% of base-load, 15% of intermediate and 35% of peaking capacity. For a discussion of the factors that may affect the future earnings generated by these Orion Power assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Integration and Other Risks Associated With Our Orion Power Assets" in Item 7 of this Form 10-K.

Market Framework. We sell the power generated by our Midwest regional facilities into the ECAR market and the region covered by the Mid-America Interconnected Network Reliability Council (MAIN market). These markets include all or portions of the states of Illinois, Wisconsin, Missouri, Indiana, Ohio, Michigan, Virginia, West Virginia, Tennessee, Maryland and Pennsylvania. These markets are currently in a state of transition and are in the process of establishing regional transmission organizations (RTO) that would define the rules and requirements around which competitive wholesale markets in the region would develop. The FERC has approved proposals by the Midwest Independent System Operator (Midwest ISO) to administer a substantial portion of the transmission facilities in the Midwest region. The FERC also has ordered the Alliance RTO, which had a separate proposal to be the RTO for parts of the Midwest region, to explore joining the Midwest ISO. As a result, the final market structure for the Midwest region remains unsettled. The timing of the development of RTO and the extent to which the Midwest ISO and the Alliance RTO would combine is currently unknown. In addition, some states within these markets have restructured their electric power markets to competitive markets from traditional utility monopoly markets, while others have not. Currently the transmission infrastructure in these markets is generally owned by non-independent market participants, some of which are our competitors, which has the potential to create market anomalies. Transmission constraints exist in these markets and have been managed by the owners of the transmission infrastructure, subject to transmission tariffs and protocols regulated by the FERC.

We currently sell power from our facilities in the Midwest region to customers under bilateral contracts that are generally non-standard with highly negotiated terms and conditions. Our customers include municipalities, electric cooperatives, integrated utilities, transmission and distribution utilities and power marketers. Direct customer sales, in addition to other physical and financial transactions enable us to hedge a portion of our generation portfolio. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generating assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

Florida and Other Southeastern Markets

Facilities. As of December 31, 2001, we owned, or owned interests in, three power generation facilities with an aggregate net generating capacity of 979 MW located in the states of Florida and Texas. These facilities include one gas and oil-fired generation facility with an aggregate net generating capacity of 619 MW located near Titusville, Florida. This facility can be operated as either an intermediate or a peaking facility. We also own a 464 MW gas and oil-fired peaking generation facility in Osceola County, Florida. Two of the three generating units of this plant with an aggregate net generating capacity of 310 MW commenced commercial operation in December 2001. We expect the remaining generating unit at this facility will begin commercial operation in the second quarter of 2002. In addition, we own a 50% interest in a 100 MW gas-fired base-load/cogeneration facility located in Orange, Texas. Air Liquide owns the other 50% interest in this plant which has been in commercial operation since December 1999.

We have begun construction on an 804 MW gas-fired intermediate/peaking facility in Choctaw County, Mississippi. We expect this facility will begin commercial operation in the second quarter of 2003. This facility

is being constructed under the terms of a construction agency agreement under a synthetic leasing arrangement. Upon completion of the construction of this facility, we will have the right to lease, purchase or remarket the facility. For additional information regarding the construction agency agreement, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Sources and Uses of Cash — Reliant Resources-unregulated businesses — Consolidated Sources of Cash — Off-Balance Sheet Transactions — Construction Agency Agreements" in Item 7 of this Form 10-K, and Note 14(l) to our consolidated financial statements.

Market Framework. We currently conduct the majority of our Southeast regional operations in the state of Florida. The state of Florida, other than a portion of the western panhandle, constitutes a single reliability council and contains approximately 5% of the United States population. The transmission-owning utilities in Florida have proposed establishing an independent system operator to assume control of the transmission system and undertake to define the rules and requirements for a competitive wholesale market. The timing of the development of an independent system operator for the Florida market is currently unknown. Under its present structure, the Florida market is dominated by incumbent utilities. There are a number of statutory and regulatory restrictions that negatively impact the development of additional power generation facilities in the region.

We currently sell power from our facilities in the Florida market under bilateral contracts that are non-standard and highly negotiated for terms and conditions. Until the rules for system operations are established, we expect limited trading opportunities will exist in the Florida market. The customers who participate in power transactions in this region include municipalities, electric cooperatives and integrated utilities. We sell capacity and energy to customers in the Florida market, however a market for ancillary services has not developed. Forward hedging of a portion of our Florida portfolio is generally accomplished through customer-tailored, multi-year sale agreements as no liquid, over-the-counter or auction markets currently exist in Florida. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generation assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

With respect to our facilities in East Texas and Mississippi, several of the transmission-owning utilities in the Southeast region have formed the SETrans Grid Company (SETrans RTO) that they are proposing to serve as the region's RTO. The proposed SETrans RTO would manage, but not own, the transmission grid in the region and operate forward and spot markets for energy. The SETrans RTO has filed a status report with the FERC, but has not filed tariffs or protocols and has not been approved as the region's RTO.

West Region

Facilities. As of December 31, 2001, we owned, or owned interests in, seven electric power generation facilities with an aggregate net generating capacity of 4,635 MW located in the states of California, Nevada and Arizona. These facilities include approximately 20% of base-load, 75% of intermediate and 5% of peaking capacity. Our facilities in the West region include five facilities with an aggregate net generating capacity of 3,800 MW located in California. We also own a 50% interest in a 490 MW gas-fired, base-load, peaking facility located near Las Vegas, Nevada. Sempra Energy owns the other 50% interest in this plant. In addition, we own a 590 MW gas-fired, base-load, peaking generation facility in Casa Grande, Arizona. This facility was placed in commercial operation in the fourth quarter of 2001. We also have a 548 MW gas-fired, base-load, peaking generation facility under construction in Nevada. We expect this facility will begin commercial operation in the fourth quarter of 2003.

Market Framework. Our West regional market includes the states of Arizona, California, Oregon, Nevada, New Mexico, Utah and Washington. Generally we sell the power generated by our California and Nevada facilities to customers located in the Los Angeles basin of southern California. We also sell power generated by our Nevada facility to customers located in southern Nevada. Our customers in these states include power marketers, investor-owned utilities, electric cooperatives, municipal utilities and the California

Independent System Operator (Cal ISO) acting on behalf of load-serving entities. We sell power and ancillary services to these customers through a combination of bilateral contracts and sales made in the Cal ISO's day-ahead and hour-ahead ancillary services markets and its real-time energy market. The Cal ISO does not currently maintain a market for capacity; however, a capacity market has recently been proposed by the Cal ISO under its market mitigation plan for the California market.

We have agreed to sell up to 100% of the power generated by our Arizona facility to the Salt River Project Agricultural Improvement and Power District of the State of Arizona under a long-term power purchase agreement. Bilateral contracts, in addition to other physical and financial transactions, enable us to hedge a portion of our generation portfolio. For a more complete description of our hedging strategy and a summary of the consolidated hedge position of our United States generating assets, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K. In addition, although we do not own generation facilities in the states of Oregon, New Mexico, Utah and Washington, our trading and marketing operations purchase and deliver energy commodities in these states.

Our operations in the California market are subject to numerous environmental and other regulatory restrictions. Permits issued by local air districts restrict the output of some of our generating facilities. In addition, certain air districts require us to purchase emission credits to offset NOx emissions from our facilities.

In response to California's electricity market restructuring initiative, the FERC issued a series of orders in 1996 and 1997 approving a wholesale market structure administered by two independent non-profit corporations: the Cal ISO, responsible for operational control of the transmission system and the purchase or sale of electricity in "real-time" to balance actual supply and demand, and the California Power Exchange (Cal PX), responsible for conducting auctions for the purchase or sale of electricity on a day-ahead or day-of basis. As part of this market restructuring, California's distribution utilities sold essentially all of their gas-fired plants to third-party generators. The utilities were required to sell their remaining generation into the Cal PX markets and purchase all of their power requirements from the Cal PX markets at market-based rates approved by the FERC. California's regulatory system initially prohibited the utilities from entering into forward contracts to cover the bulk of their customers' requirements. Retail electricity rates were initially frozen at levels in effect on June 10, 1996, with a 10% rate reduction for residential and smaller commercial customers. When wholesale power costs began to rise dramatically in 2000, driven by a combination of factors, including higher natural gas prices and emission allowance costs, reduction in available hydroelectric generation resources, increased demand and decreases in net imports, some of the California utilities were unable to recover their purchased power costs through the retail rates they were allowed to charge. As a result, the utilities accumulated huge debts to wholesale power suppliers, including us. The Cal ISO currently is conducting a major market redesign process that, if approved by the FERC, could change the structure of the markets operated by the Cal ISO, including changes to market monitoring and mitigation, congestion management and capacity obligations. For a discussion of litigation and other legal proceedings related to energy sales in California, the impact of current regulations on our West region and related uncertainty associated with the California wholesale market, please read "— Regulation — Federal Energy Regulatory Commission" in Item 1 of this Form 10-K, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Uncertainty in the California Market" in Item 7 of this Form 10-K and Notes 14(f) and 14(g) to our consolidated financial statements.

In Nevada and Arizona, there is presently no RTO in place to manage the transmission systems or to operate energy markets, although one RTO working group is evaluating the establishment of an organization that would assume control, subject to FERC approval, over the transmission systems of the utilities operating in this region. The FERC has recently expressed its intention to pursue the establishment of an RTO in the West region.

Additionally, in Nevada and Arizona, state-level regulatory initiatives may impact competition in the electric sector. In Nevada, the state legislature has passed legislation prohibiting the state's investor-owned utilities from divesting generation. Similarly, in Arizona, proceedings are pending before the Arizona Corporation Commission that would allow the Arizona Public Service Company to avoid a requirement to seek competitive bids for 50% of the Arizona Public Service Company's generation needs.

ERCOT Region

Facilities. Through Reliant Resources, we currently own a partially operational 781 MW gas-fired, combined cycle, cogeneration facility in Channelview, Texas. 170 MW of this facility's capacity is currently operational and 611 MW are under construction. We expect the remaining generating units for this facility will begin commercial operations in the third quarter of 2002. This facility is not part of our Electric Operations business segment. For more information on that segment and the facilities that are part of our Texas generation business, please read "Electric Operations" in Item 1 of this Form 10-K.

Market Framework. For information regarding the market framework of the ERCOT region, please read "Electric Operations — ERCOT Market Framework" in Item 1 of this Form 10-K.

Long-Term Purchase and Sale Agreements

In the ordinary course of business, and as part of our hedging strategy, we enter into long-term sales arrangements for power, as well as long-term purchase arrangements. For information regarding our long-term fuel supply contracts, purchase power and electric capacity contracts and commitments, electric energy and electric sale contracts and tolling arrangements, please read Notes 5, 14(a) and 14(b) to our consolidated financial statements. For information regarding our hedging strategy relating to such long-term commitments, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K.

Development Activities

As of December 31, 2001, we had 3,587 MW (3,391 MW, net of 196 MW to be retired upon completion of one facility) of additional net generating capacity under construction, including 2,120 MW of facilities owned by off-balance sheet special purpose entities, that are being constructed under construction agency agreements pursuant to synthetic leasing arrangements. Upon the completion of the construction of these facilities, we expect that we will lease these facilities from their owners. For additional information regarding the construction agency agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Sources and Uses of Cash — Reliant Resources-unregulated businesses — Consolidated Sources of Cash — Off-Balance Sheet Transactions — Construction Agency Agreements" in Item 7 of this Form 10-K and Note 14(l) to our consolidated financial statements.

In addition, Orion Power had three projects totaling 1,054 MW under construction as of December 31, 2001. However, at this time, we have decided to postpone a 250 MW project in Florida because of capital market and economic considerations. With improved capital market conditions and required approvals from Florida authorities on a newly configured 500 MW design, we would plan to proceed with construction in the future. Also, Orion Power had two projects under advanced development as of December 31, 2001, which have been deferred. A 1,088 MW project in Maryland has been postponed due to capital market considerations and because we believe that the PJM market will be sufficiently supplied for the next few years. A repowering project in New York City with a total capacity of 1,608 MW has been postponed until we see an improvement in the capital markets.

As a result of several recent events, including the United States economic recession, the price decline of our industry sector in the equity capital markets and the downgrading of the credit ratings of several of our significant competitors, the availability and cost of capital for our business and the businesses of our

competitors has been adversely affected. In response to these events and the intensified scrutiny of companies in our industry sector by the rating agencies, we have reduced our planned capital expenditures by $2.7 billion over the 2002 — 2006 time frame.

Domestic Trading, Marketing, Power Origination and Risk Management Services Operations

In addition to our power generation operations, we trade and market power, natural gas and other energy-related commodities and provide related risk management services to our customers. Our domestic trading, marketing, power origination and risk management operations complement our domestic power generation operations by providing a full range of energy management services. These services include management of the sales and marketing of energy, capacity and ancillary services from these facilities, and also management of the purchase and sale of fuels and emission allowances needed to operate these facilities. Generally, we seek to sell a portion of the capacity of our domestic facilities under fixed-price sale contracts, fixed-capacity payments or contracts to sell power at a predetermined multiple of either gas or oil prices. This provides us with certainty as to a portion of our margins while allowing us to maintain flexibility with respect to the remainder of our generation output. We evaluate the regional forward power market versus our own fundamental analysis of projected future prices in the region to determine the amount of our capacity we would like to sell and the terms of sale pursuant to longer-term contracts. We also take operational constraints and operating risk into consideration in making these determinations. Generally, we seek to hedge a portion of our fuel costs, which are usually linked to a percentage of our power sales. We also market energy-related commodities and offer physical and financial wholesale energy marketing and price risk management products and services to a variety of customers. These customers include natural gas distribution companies, electric utilities, municipalities, cooperatives, power generators, marketers or other retail energy providers, aggregators and large volume industrial customers.

The following table illustrates the growth of our physical power and gas trading volumes since 1999.

Trading Volumes

	For the Year Ended December 31		
	1999	2000	2001
Total Power (MMWh) (1)	82	172	300
Total Gas (Bcf) (2)	1,564	2,423	3,508

(1) Million megawatt hours.

(2) Billion cubic feet.

Electric Power Trading and Marketing. We purchase electric power from other generators and marketers and sell power primarily to electric utilities, municipalities and cooperatives and other marketing companies. Our trading and marketing group is also responsible for the marketing of power produced from the power plants we own. We also provide risk management, physical and financial fuel purchase and power sales and optimization services to our customers.

Power Origination. Some of our employees focus on developing and providing customers with long-term customized products (power origination products). These products are designed and negotiated on a case-by-case basis to meet the specific energy requirements of our customers. Our power origination teams work closely with our trading and marketing group and our power generation group to sell long-term products from our power generation assets. They also work to leverage our market knowledge to capture attractive opportunities available through selling products that combine or repackage energy products purchased from third parties with other third-party products or with products from our power generation assets. Our efforts to sell power origination products from our power generation assets have been focused on longer-term forward sales to municipalities, cooperatives and other companies that serve end users, as well as sales of near-term products that are not widely traded. Our power origination products that combine or repackage third-party

products are generally highly structured and therefore require the application of our commercial capabilities (*e.g.*, power trading and asset positions).

Natural Gas Trading and Marketing. We purchase natural gas from a variety of suppliers under daily, monthly and term, variable-load and base-load contracts that include either market sensitive or fixed pricing provisions. We sell natural gas under sales agreements that have varying terms and conditions, most of which are intended to match seasonal and other changes in demand. We sold an average of 9.6 Bcf per day of natural gas in 2001, an average of 6.6 Bcf per day in 2000 and an average of 4.3 Bcf per day in 1999, some of which was sold to the natural gas distribution company subsidiaries of Reliant Energy. We plan to continue to purchase natural gas to supply to our power plants.

Our natural gas marketing activities include contracting to buy natural gas from suppliers at various points of receipt, aggregating natural gas supplies and arranging for their transportation, negotiating the sale of natural gas and matching natural gas receipts and deliveries based on volumes required by customers.

We arrange for, schedule and balance the transportation of the natural gas we market from the supply receipt point to the purchaser's delivery point. We generally obtain pipeline transportation to serve our customers. Accordingly, we use a variety of transportation arrangements for our customers, including short-term and long-term firm and interruptible agreements with intrastate and interstate pipelines. We also utilize brokered firm transportation agreements when dealing on the interstate pipeline system. As of December 31, 2001, we held over two bcf per day of firm transportation in the United States. In the normal course of business it is common for us to hedge the risk of pipeline transportation expenses through "basis swaps." To the extent we have contractually secured pipeline transportation rights in order to fulfill our obligations to sell gas at specific delivery points, or to acquire gas for our own requirements at generation facilities as part of our hedging strategy for power sales, and a pipeline experiences a force majeure event, our ability to transport gas on a contracted capacity basis could become impaired, which could affect the integrity of our hedged position.

We also enter into various short-term and long-term firm and interruptible agreements for natural gas storage in order to offer peak delivery services to satisfy winter heating and summer electric generating demands. Natural gas storage capacity allows us to better manage the unpredictable daily or seasonal imbalances between supply volumes and demand levels. In addition to entering into contracts of natural gas storage capacity in strategic locations throughout the country, we are actively pursuing a natural gas storage development plan. These services are also intended to provide an additional level of performance security and backup services to our customers.

Other Commodities and Derivatives. We trade and market other energy-related commodities. We use derivative instruments to manage and hedge our fixed-price purchase and sale commitments and to provide fixed-price or floating-price commitments as a service to our customers and suppliers. We also use derivative instruments to reduce our exposure relative to the volatility of the cash and forward market prices and to protect our investment in storage inventories. For additional information regarding our financial exposure to derivative instruments, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Risks Associated with Our Hedging and Risk Management Activities" in Item 7 of this Form 10-K and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K.

Intercontinental-Exchange. In July 2000, we, along with five other natural gas and power companies, American Electric Power, Aquila Energy, Duke Energy, El Paso Corporation and Mirant Corporation, made an investment in Intercontinental-Exchange, a new, web-based, on-line trading platform (*www.intcx.com*) for trading various commodities including precious metals, crude oil and refined products, natural gas and electricity. The other five natural gas and power companies, along with us, own less than 50% of Intercontinental-Exchange. In June 2001, Intercontinental-Exchange acquired the International Petroleum Exchange. With this acquisition, Intercontinental-Exchange became the first company to offer both an exchange trading over-the-counter commodity contracts and an exchange trading commodity futures contracts. At the same time, Intercontinental-Exchange announced plans to integrate the two types of exchanges into a single electronic trading platform. Our decision to invest, as one of a group of natural gas and power

companies, in Intercontinental-Exchange was based on a desire to support the development of a neutral, anonymous, electronic trading platform for bilateral energy transactions. We believe the commercial success of such an exchange model will benefit us by contributing to improved price transparency and transaction liquidity in the wholesale energy markets. The principal online competitors of Intercontinental-Exchange are currently TradeSpark.com and the NYMEX, a traditional futures exchange that has announced an online initiative.

Risk Management Controls. For information regarding our risk management structure and accounting policies, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Trading and Marketing Operations" in Item 7 of this Form 10-K and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K.

Competition

For a discussion of competitive factors affecting our Wholesale Energy business segment, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Increasing Competition in Our Industry" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

EUROPEAN ENERGY

Our European Energy business segment, which is conducted through Reliant Resources, includes 3,476 MW of power generation assets located in the Netherlands and a related trading and power origination operation. This business segment includes the operations of Reliant Energy Power Generation Benelux N.V. (formerly UNA N.V.) (REPGB) and Reliant Energy Trading & Marketing B.V. and its affiliates.

In 2001, we evaluated strategic alternatives for our European Energy business segment, including a possible sale. We completed our evaluation and have determined that given current market conditions and prices, it is not advisable to sell our European Energy operations. Consequently, we decided to continue to own and operate our European Energy business segment and expand our trading and origination activities in Northwest Europe. Our European Energy business segment will remain with Reliant Resources in the Separation and will not be part of our business after the Distribution.

European Power Generation Operations

Facilities. As of December 31, 2001 we owned five electric power generation facilities in the Netherlands with an aggregate net generating capacity of 3,476 MW and include approximately 39% of base-load, 36% of intermediate and 25% of peaking capacity. Our facilities are grouped in three clusters adjacent to the cities of Amsterdam, Utrecht and Velsen. In 2001, our generation facilities produced 14 million MWh, an amount which represented approximately 13% of the electricity production of the Netherlands (excluding electricity generated by cogeneration or other industrial processes). In addition to electricity, our generating stations sell heated water produced as a byproduct of the generation process for use in providing heating (district heating) to the cities of Amsterdam, Nieuwegein, Utrecht and Purmerend.

In 2001, approximately 51% of our European Energy business segment's generation output was natural gas-fired, 30% was coal-fired, 18% was blast furnace gas-fired and less than 1% was oil-fired. Our European Energy business segment purchases substantially all of its gas fuel requirements under medium to long-term gas purchase contracts with N.V. Nederlandse Gasunie, the primary supplier and transporter of natural gas in the Netherlands. The purchase price and transportation costs for natural gas under these contracts are calculated on the basis of regulated tariffs.

Our European Energy business segment historically purchased all of its coal requirements under short-term contracts with a coal trading and supply company now owned by two of the Dutch generation companies. In December 2001, REPGB and the other shareholder of the coal trading and supply company agreed to terminate future coal purchases through this entity effective in mid-2002. Our European Energy business

segment intends to obtain its future coal requirements through short to medium-term forward purchase contracts on the open market through a variety of suppliers and brokers.

One of our European Energy generation stations, which has a production capacity of 144 MW, uses blast furnace gas, an industrial waste gas generated by a steel plant adjacent to the generation station, as its fuel. Two of our other European Energy business segment's generation plants have the flexibility to operate using blast furnace gas. We purchase the blast furnace gas from the adjacent steel plant under a medium-term and a long-term contract. We purchase our fuel oil requirements on the open market.

We acquired REPGB in October 1999 for approximately $1.9 billion (based on the then applicable exchange rate of 2.06 Dutch Guilders (NLG) per U.S. dollar). For information regarding the acquisition, please read Note 3(b) to our consolidated financial statements.

Market Framework. Our European Energy business segment produces, buys and sells electricity, gas and other energy-related commodities in the Northern European wholesale market. Its generation production activities are centered in the Netherlands, where it is one of the four large-scale generation companies. It operates five generation facilities with an installed capacity of 3,476 MW. Its energy trading and origination operations concentrate their activities primarily in the Netherlands, Germany and the Scandinavian regions. In the fourth quarter of 2001, our European Energy business segment expanded its electricity trading operations to the United Kingdom.

The primary customers of our European Energy business segment are electric distribution companies, large industrial consumers and energy trading companies. We sell electricity and other energy-related commodities primarily in the form of forward purchase contracts transacted in the over the counter markets, on various European energy exchanges and in individually negotiated transactions with individual counterparties. To a lesser extent, we also engage in transactions involving financial energy-related derivative products.

The most significant factor affecting the markets in which our European Energy business segment operates has been the recent deregulation of the Dutch and certain other European wholesale energy markets, including access on a non-discriminatory basis to high voltage transmission grid systems, the establishment of new energy exchanges and other events. Notwithstanding these factors, the scope and pace of the future liberalization of the European energy markets is uncertain. For example, access to some European markets continues to be subject to transmission and other constraints. In some cases, fuel suppliers continue to operate in largely regulated markets not yet open to full competition.

European Trading and Power Origination Operations

Our European Energy business segment's trading and power origination operations are centered in Amsterdam, Netherlands, with additional offices in London and Frankfurt. Our European Energy business segment trades electricity and fuel products in the Netherlands, Germany, Austria, Switzerland, the United Kingdom and the Scandinavian countries. Our marketing operations focus on distribution companies and large industrial and commercial customers in the Benelux and German markets. As of December 31, 2001, our European Energy business segment had entered into forward purchase and sale contracts, and associated hedging transactions, covering approximately 18.6 million MWh for delivery in 2002.

Our European Energy business segment's trading and power origination operations seek to utilize a business model, including risk management and related control policies, similar to that utilized in our Wholesale Energy operations in the United States. There are, however, significant differences in the United States and European markets. Among other things, European energy markets involve increased currency hedging requirements (the Euro and non-Euro currencies), and more complicated cross-border tax and transmission tariff systems than in the United States. In addition, European energy markets are significantly less mature than United States energy markets in terms of liquidity, the scope and complexity of trading and marketing products, the use of standardized market-based trading contracts and other aspects.

In addition, there exist greater uncertainties in some European jurisdictions as to the enforceability of certain contract-based mechanisms to hedge risks, such as the enforceability of automatic termination rights and rights of set-off upon bankruptcy, limitations on liquidated damages and the rules by which European

courts construct contracts. In many civil law jurisdictions, courts reserve the right to interpret contracts based upon principles of good faith and fairness as opposed to a literal construction of the contract.

As of December 31, 2001, we had provided an aggregate of $831 million in guarantees with respect to contract obligations of our European Energy business segment.

Competition

For a discussion of competitive factors affecting our European Energy business segment, please read "Management's Discussion and Analysis of Financial Condition and Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our European Energy Operations — Competition in the European Market" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

RETAIL ENERGY

Our Retail Energy business segment provides electricity and related services to retail customers primarily in Texas through Reliant Energy Retail Services, LLC (Residential Services), Reliant Energy Solutions, LLC (Solutions) and StarEn Power, LLC (StarEn Power), all of which are wholly owned subsidiaries of Reliant Resources. Our Retail Energy business segment will remain with Reliant Resources in the Separation and will not be part of our business after the Distribution. As a retail electric provider, generally our Retail Energy business segment procures or buys electricity from wholesale generators at unregulated rates, sells electricity at generally unregulated rates to its retail customers and pays the local transmission and distribution regulated utilities a regulated tariff rate for delivering the electricity to its customers. Our Retail Energy business segment became a provider of retail electricity in Texas when that market began opening to retail competition in late 2001 and fully opened to retail competition in January 2002. In January 2002, our Retail Energy business segment began to provide retail electricity services to all of the approximately 1.7 million customers of Reliant Energy HL&P's electric utility located in its service area who did not take action to select another retail electric provider. Our Retail Energy business segment provides electricity and related products and services to residential and small commercial (*i.e.*, small and medium-sized business customers with a peak demand for power at or below one MW) customers through Residential Services, and offers customized, integrated electric commodity and energy management services to large commercial, industrial and institutional (*e.g.*, hospitals, universities, school systems and government agencies) customers through Solutions for customers with a peak demand for power of greater than one MW. Residential Services, Solutions and StarEn Power have been certified as retail electric providers by the Texas Utility Commission. StarEn Power has been appointed by the Texas Utility Commission to be the provider of last resort (POLR) in certain areas of the State of Texas. Under the Texas Electric Restructuring Law, a POLR is required to offer a standard retail electric service package to requesting customers of a class designated by the Texas Utility Commission within the POLR's territory at a fixed, nondiscountable rate.

In preparation for retail electric competition in Texas, Reliant Resources expanded its infrastructure of information technology systems, business processes and staffing levels to meet the needs of its retail businesses. These include a customer care system module and wholesale/retail energy supply, risk management, e-commerce, scheduling/settlement, customer relationship management and sales force automation systems. As of December 31, 2001, Reliant Resources had invested $153 million in retail infrastructure development. For additional information regarding the Texas retail electric market, please read "— Market Framework," "— Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" in Item 1 of this Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations — Competition in the Texas Market" in Item 7 of this Form 10-K.

Residential Services

Residential Services provides electricity to residential retail and small commercial customers in Texas. As of January 1, 2002, Residential Services was the retail electric provider for approximately 1.5 million

residential customers located in the Houston metropolitan area, making us the second largest retail electric provider in Texas as of that date. Residential Services' marketing strategy for residential customers emphasizes reliability and trust with our customers, and focuses on savings, value and customer service. Reliant Resources launched an advertising campaign to reposition its brand in the Houston and Dallas/ Fort Worth metropolitan areas in the second half of 2001.

As the affiliated retail electric provider, or successor in interest, to Reliant Energy HL&P, Residential Services was also the retail electric provider for approximately 200,000 small commercial customers in the Houston metropolitan area as of January 1, 2002. Residential Services' marketing strategy for small commercial customers uses a combination of direct marketing and individual sales calls to establish its brand and to attract additional customers.

As the affiliated retail electric provider, Residential Services will not be permitted to sell electricity to residential and small commercial customers in Reliant Energy HL&P's service territory at a price other than the price to beat until January 1, 2005, unless before that date the Texas Utility Commission determines that 40% or more of the amount of electric power that was consumed in 2000 by the relevant class of customers in the service territory is committed to be served by other retail electric providers. In addition, the Texas Electric Restructuring Law requires Reliant Resources, as the affiliated retail electric provider, to make the price to beat available to residential and small commercial customers in Reliant Energy HL&P's service territory through January 1, 2007, if requested by such customers. For more information about the price to beat, please read "— Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" in Item 1 of this Form 10-K.

Solutions

Solutions provides electricity and energy services to the large commercial, industrial and institutional customers with whom it has signed contracts. In addition, it provides electricity at previously established default rates to those large commercial, industrial and institutional customers in the service territory of Reliant Energy HL&P who have not entered into a contract with another retail electric provider. The majority of Solutions' revenues will come from the sale of electricity to its customers. In order to be classified as a large commercial customer, an electricity customer may aggregate the purchase of electricity for its own use at multiple locations such that the total peak demand exceeds one MW.

In addition to providing electricity, Solutions provides customized, integrated energy solutions, including risk management and energy services products, and demand side and energy information services to large commercial, industrial and institutional customers. Since its formation in April 1996, Solutions has completed over 220 energy services projects for large commercial, industrial and institutional clients. The services that Solutions provides its customers include the replacement or upgrade of energy-intensive capital equipment, the financing of energy-intensive equipment, infrastructure optimization, substation development and maintenance and power quality assurance.

Solutions is recognized as the affiliated retail electric provider, or successor in interest, to Reliant Energy HL&P for large commercial, industrial and institutional customers. Solutions targets institutional, manufacturing, industrial and other large commercial customers, including multi-site retailers and restaurants, petroleum refineries, chemical companies, real estate management firms, educational institutions and healthcare providers. As of December 31, 2001, this customer segment in Texas included approximately 1,750 buying organizations consuming an aggregate of approximately 16,000 MW of electricity at peak demand. As of December 31, 2001, Solutions had signed contracts with customers representing a peak demand of approximately 3,700 MW and serving approximately 12,000 meter locations.

StarEn Power

StarEn Power serves as the POLR in portions of the state of Texas, as designated by the Texas Utility Commission. For 2002, StarEn Power has been appointed to serve as the POLR for residential and small commercial customers in the western portion of the Dallas/Fort Worth metropolitan area formally served by TXU Electric Company. In addition, StarEn Power has been appointed as the POLR in the service territory

of Reliant Energy HL&P for large commercial, industrial and institutional customers. The rates and terms under which StarEn Power provides service are governed by the terms of a settlement agreement between StarEn Power and various interested parties approved by the Texas Utility Commission. For additional information regarding StarEn Power's POLR obligations, rates and terms of service, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations — Obligations as a Provider of Last Resort" in Item 7 of this Form 10-K.

Market Framework

Generally, under the Texas Electric Restructuring Law, the retail electric provider procures or buys electricity from wholesale generators, sells electricity at retail to its customers and pays the transmission and distribution utility a regulated tariffed rate for delivering electricity to its customers. All retail electric providers in an area pay the same rates and other charges for transmission and distribution, whether or not they are affiliated with the transmission and distribution utility for that area. The transmission and distribution rates in effect as of January 1, 2002 for each utility were set through rate cases before the Texas Utility Commission. For more information regarding the retail market framework in Texas, please read "— Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" in Item 1 of this Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations" in Item 7 of this Form 10-K.

Retail Energy Supply

In Texas, our Wholesale Energy group and our Retail Energy group work together in order to determine the price, demand and supply of energy required to meet the needs of our Retail Energy business segment's customers. Our Wholesale Energy trading and marketing operations are responsible for commodity pricing, risk assessment and supply procurement for our Retail Energy business segment. Our Retail Energy business segment manages retail pricing decisions and forecasts the demand for the procurement of electricity by the Wholesale Energy business segment. The costs of our trading, marketing and risk management services associated with obtaining the electricity supply for our retail customers in Texas are borne by our Retail Energy business segment. Our Wholesale Energy group acquires supply for our Retail Energy business segment by several means. Wholesale Energy may purchase capacity from non-affiliated parties in the state mandated auctions. Please read "Electric Operations — Generation — State Mandated Capacity Auctions" and "— Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" in Item 1 of this Form 10-K for more information about these auctions. Under the terms of the master separation agreement between Reliant Resources and Reliant Energy, Reliant Resources is entitled to purchase, prior to our submission of capacity to auction, 50% (but not less than 50%) of the capacity we have available to auction in the contractually mandated auctions at the prices bid by third parties in these auctions. Please read "Electric Operations — Generation — Contractually Mandated Capacity Auctions" in Item 1 of this Form 10-K for more information about these auctions. Whether or not Reliant Resources exercises the foregoing right, it may submit bids to purchase in the contractually mandated auctions, but cannot participate in state mandated auctions conducted by our Texas generation business. Wholesale Energy entered into bilateral contracts with third parties for capacity, energy and ancillary services. Wholesale Energy continuously monitors and updates these positions based on retail sales forecasts and market conditions.

Competition

For a discussion of competitive factors affecting our Retail Energy business segment, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations — Competition in the Texas Market" in Item 7 of this Form 10-K, which section is incorporated herein by reference.

LATIN AMERICA

Effective December 1, 2000 (Measurement Date), our board of directors approved a plan to dispose of our Latin America business segment through sales of its assets. At the time, our major Latin America investments consisted of interests in cogeneration projects, utilities and other power projects in Argentina, Brazil and Colombia. We began disposing of our Latin America assets and reporting the results of our Latin America business segment as "discontinued operations" in our 2000 consolidated financial statements in accordance with Accounting Principles Board (APB) Opinion No. 30 "Reporting the Results of Operations — Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," (APB Opinion No. 30).

By December 2001, we had disposed of all of our Latin America assets except for our Argentine investments, which consisted of a 100% interest in a corporation formed to develop, own and operate a 160 MW cogeneration project (Argener) located at a steel plant near San Nicolas, Argentina and a 90% interest in a utility in north-central Argentina (EDESE). We were in negotiations to dispose of Argener and EDESE, but the negotiations terminated in December 2001 in light of recent adverse economic developments in Argentina. Under applicable accounting rules, because we were not able to dispose of Argener and EDESE within one year of the Measurement Date, our remaining investments in our Latin America business segment are no longer classified as discontinued operations, and the related amounts have been reclassified into continuing operations in our consolidated financial statements. We will continue to evaluate options related to the future disposition of these assets. For more information regarding the accounting treatment of our Latin America business segment, please read Note 19 to our consolidated financial statements.

OTHER OPERATIONS

In 2001, our Other Operations business segment included:

- the operations of Reliant Energy Thermal Systems, Inc. (Thermal Systems);
- the operations of Reliant Energy Power Systems, Inc. (Power Systems);
- the operations of our communications business (Communications);
- the operations of our venture capital division (New Ventures);
- various office buildings and other real estate used in our business operations;
- unallocated corporate costs; and
- intersegment eliminations.

Except for Thermal Systems and Power Systems, we conducted the operations of our Other Operations business segment through Reliant Resources and one or more of its subsidiaries. After the Separation, our Other Operations business segment will consist primarily of Thermal Systems, Power Systems, office buildings and other real estate used in our business operations and unallocated corporate costs.

Reliant Energy Thermal Systems

Thermal Systems provides energy management services to commercial and industrial consumers. These services include operations and maintenance services, energy management services, distributed generation services, Internet-based facilities/energy management services, temporary cooling and electrical services, project and construction management services and engineering consulting services. Thermal Systems also owns an interest in the Northwind Houston L.P. (Northwind) district energy system in partnership with a third party. Northwind provides chilled water services to selected buildings in Houston's downtown central business district. Northwind's customers include Astros Field, and various office buildings, hotels and high-rise residential developments. Thermal Systems and the third party have an agreement in principle concerning Thermal System's purchase of the third party's interest in Northwind.

Reliant Energy Power Systems

Power Systems is developing a natural-gas-fueled proton exchange membrane fuel cell system targeted at the domestic residential market. Power Systems licenses core technology from Texas A&M University and has developed additional fuel cell technology focused on pursuing its goal of developing and building a low-cost, low-pressure fuel cell using commercially available materials and volume manufacturing design techniques.

New Ventures

Our New Ventures division manages our existing new technology investments and identifies and invests in promising new technologies and businesses that relate to our energy services operations. Focus areas for investment include distributed generation, clean energy and energy industry software and systems.

Generally, we make our investments either directly or indirectly as limited partners in venture capital funds. As of December 31, 2001, we have invested approximately $35 million in five venture capital funds with an energy and utility focus and have made commitments to invest an additional $11 million in these funds. As of December 31, 2001, these funds held investments in 43 companies. Excluding our investment in Grande Communications, Inc. discussed below, New Ventures' direct investment portfolio consists of eight companies with a total of $7 million invested as of December 31, 2001.

In September 2000, we committed to make a $25 million investment in Grande Communications, Inc., which was completed in August 2001. Grande Communications is a Texas-based communications company building a deep fiber broadband network that will offer bundled services, including high-speed Internet, all-distance telephone and advanced cable entertainment to homes and businesses. We invested a further $1 million in Grande Communications in October 2001 as part of a larger debt and equity financing for the company. Grande Communications has announced its intention to build a broadband network in the Houston area and has secured a cable franchise from the City of Houston. The Houston build out will be in addition to the Central Texas cities of Austin, San Marcos, and San Antonio which are already under development.

Communications

During the third quarter of 2001, we decided to exit our Communications business. The business served as a facility-based competitive local exchange carrier and Internet services provider and owned network operations centers and managed data centers in Houston and Austin. Our exit plan was substantially completed in the first quarter of 2002. For more information regarding the exiting of our Communications business, please read Note 20 to our consolidated financial statements.

OUR BUSINESS GOING FORWARD

Our business and operations are changing significantly as a result of the Texas Electric Restructuring Law and the Separation. Below is a summary of the principal changes to our business and operations that have occurred and that we anticipate will occur due to the Texas Electric Restructuring Law and the Separation.

Separation of Reliant Energy HL&P's Operations. Because the Texas Electric Restructuring Law requires the separation of generation, transmission and distribution and retail electric sales operations of electric utilities in Texas, Reliant Energy HL&P no longer operates as a traditional, vertically-integrated utility. The retail electric sales operations of Reliant Energy HL&P were transferred to, and have been operated by, subsidiaries of Reliant Resources. Since January 1, 2002, retail customers of Reliant Energy HL&P and other investor-owned electric utilities in Texas have been entitled to purchase their electricity from any of a number of certified retail electric providers, including Reliant Resources, at generally unregulated rates. Reliant Energy (of which Reliant Energy HL&P is an unincorporated division) no longer provides retail electric services to customers, except through Reliant Resources, and, upon completion of the Distribution, such services will be provided at rates separately and independently of CenterPoint Energy by Reliant Resources and its subsidiaries and by other retail electric providers.

Since January 1, 2002, we have been selling electric energy from our Texas generation business to wholesale purchasers, including retail electric providers, at unregulated rates pursuant to the state mandated auctions and the contractually mandated auctions. We plan to transfer our Texas generation business to Texas Genco in connection with the Restructuring. Pursuant to the Texas Genco Option, Reliant Resources has the option to acquire our interest in Texas Genco in 2004. As a result of these changes, our Texas generation operations are no longer conducted as part of an integrated utility and will comprise a new business segment in 2002, Electric Generation.

Distribution of Reliant Resources' Stock and New Business Segment. We have transferred substantially all of our unregulated businesses to Reliant Resources and its subsidiaries. When we complete the Separation, CenterPoint Energy's business will consist principally of regulated operations. We anticipate that upon completion of the Separation described above, CenterPoint Energy's business segments will consist of the following:

- Electric Transmission and Distribution;
- Electric Generation;
- Natural Gas Distribution;
- Pipelines and Gathering; and
- Other Operations.

The Wholesale Energy, European Energy, Retail Energy and unregulated portions of our Other Operations business segments will be conducted by Reliant Resources as a separate publicly traded company.

For information regarding the effect of the changes in our business and operations on our future earnings, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Associated with the Business Separation, Restructuring and Distribution" in Item 7 of this Form 10-K.

REGULATION

We are subject to regulation by various federal, state, local and foreign governmental agencies, including the regulations described below.

Public Utility Holding Company Act of 1935

Current Status. Reliant Energy is both a public utility holding company and an electric utility company as defined in the 1935 Act; however, it is exempt from regulation as a registered holding company pursuant to Section 3(a)(2) of the 1935 Act. Although RERC Corp. is a gas utility company as defined under the 1935 Act, it is not a holding company within the meaning of the 1935 Act. Reliant Energy and RERC Corp. are currently subject to regulation under the 1935 Act with respect to certain acquisitions of voting securities of other domestic public utility companies and utility holding companies.

Section 33(a)(1) of the 1935 Act exempts foreign utility company affiliates of Reliant Energy and RERC Corp. from regulation as "public utility companies," thereby permitting Reliant Energy and RERC Corp. to invest in foreign utility companies without becoming subject to registration under the 1935 Act as a registered holding company and without approval by the SEC. The exemption, however, is subject to the SEC having received certification from each state commission having jurisdiction over the retail rates of any electric or gas utility company affiliated with Reliant Energy or RERC Corp. that such commission has the authority and resources to protect ratepayers subject to its jurisdiction and that it intends to exercise its authority. The Texas Utility Commission and the state regulatory commissions exercising jurisdiction over RERC Corp. (Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas) have provided a certification to the SEC subject, however, to the right of such commissions to revise or withdraw their certifications as to any future acquisitions of a foreign utility company. The Texas Utility Commission and the state regulatory commissions of Arkansas and Minnesota have imposed limitations on the amount of investments that can be made by

utility companies (including Reliant Energy and RERC Corp.) in foreign utility companies and, in some cases, foreign electric wholesale generating companies. These limitations are based upon a utility company's consolidated net worth, retained earnings, and debt and stockholders' equity. We currently do not plan to make any incremental investments in foreign utility companies.

Subject to some limited exceptions, Section 33(f)(1) of the 1935 Act prohibits us, as a public utility company, from issuing any security for the purpose of financing the acquisition, ownership or operation of a foreign utility company, or assuming any obligation or liability in respect of any security of a foreign utility company.

Under the Energy Policy Act of 1992, a company engaged exclusively in the business of owning and/or operating facilities used for the generation of electric energy exclusively for sale at wholesale and selling electric energy at wholesale may be exempted from regulation under the 1935 Act as an exempt wholesale generator (EWG). All but two of our electric generation facilities owned by Reliant Resources have received determinations of EWG status from the FERC. If any of these subsidiaries loses its EWG status, we would have to restructure our organization or risk being subjected to regulation under the 1935 Act. The two electric generation facilities in which Reliant Resources owns interests that are not EWGs are "qualifying facilities" under PURPA. As such, these facilities, and the subsidiaries who own them, also are exempted from regulation under the 1935 Act.

Impact on the Restructuring. SEC approval is required for CenterPoint Energy to acquire Reliant Energy and its subsidiary companies. As a result of the Restructuring, CenterPoint Energy will be a holding company within the meaning of the 1935 Act and, as such, required to register under the 1935 Act unless it is able to qualify for exemption Section 3(a)(1) of the 1935 Act provides an exemption for a holding company if it and each of its material public utility subsidiary companies carry on their utility operations substantially and predominantly in a single state in which they are all organized. While we believe that CenterPoint Energy will ultimately be in compliance with the requirements for exemption under Section 3(a)(1), RERC Corp. initially will be a material subsidiary with significant out-of-state utility operations. As described in our application to the SEC, we plan to bring CenterPoint Energy into full compliance with the standards of Section 3(a)(1) by separating the Entex, Arkla and Minnegasco operations of RERC Corp. into separate business entities. We are in the process of obtaining the necessary state approvals for the RERC Corp. separation.

In the interim, CenterPoint Energy must either obtain a temporary exemption from registration or else register under the 1935 Act until the separation of RERC Corp. is completed. We have previously submitted a request for a temporary exemption for CenterPoint Energy but believe that the new holding company could also register and obtain the necessary authority under the 1935 Act to operate during this interim period consistent with our business plan.

Following the Distribution, Reliant Resources and its subsidiaries would not be subject to the provisions of the 1935 Act either as subsidiaries or affiliates of CenterPoint Energy.

Proposals to Repeal the 1935 Act. In recent years, several bills have been introduced in Congress that would repeal the 1935 Act. Repeal or significant modification to the 1935 Act could have a significant impact on us and the electric utility industry. At this time, however, we are not able to predict the outcome of any bills to repeal the 1935 Act or the outlook for additional legislation in 2002.

Federal Energy Regulatory Commission

Natural Gas. The transportation and sale for resale of natural gas in interstate commerce is subject to regulation by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978, as amended. The FERC has jurisdiction over, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. The rates charged by interstate pipelines for interstate transportation and storage services are also regulated by the FERC.

REGT and MRT periodically file applications with the FERC for changes in their generally available maximum rates and charges designed to allow them to recover their costs of providing service to customers (to the extent allowed by prevailing market conditions), including a reasonable rate of return. These rates are normally allowed to become effective after a suspension period, and in some cases are subject to refund under applicable law, until such time as the FERC issues an order on the allowable level of rates. REGT currently is operating under such rates approved by the FERC that took effect in February 1995. MRT currently is operating under such rates that took effect in October 2001, pursuant to a rate case settlement approved by the FERC on January 16, 2002.

On February 9, 2000, the FERC issued Order No. 637, which introduces several measures to increase competition for interstate pipeline transportation services. Order No. 637 authorizes interstate pipelines to propose term-differentiated and peak/off-peak rates, and requires pipelines, including MRT and REGT, to make tariff filings to expand pipeline service options for customers. REGT and MRT made Order No. 637 compliance filings in 2000. On March 29, 2002, the FERC issued an order accepting, subject to certain modifications, a settlement agreement that would resolve REGT's Order No. 637 proceeding. On November 21, 2001, MRT filed with the FERC for approval of a settlement intended to resolve the MRT Order No. 637 compliance proceeding. The settlement was uncontested. No action on the settlement has yet been taken by the FERC.

On May 31, 2001, the FERC issued an order on rehearing establishing hearing procedures to evaluate MRT's request for authority to recover four Bcf of undercollected lost and unaccounted for gas over a three-year period. A settlement resolving all issues in this case, among other things, was filed with the FERC on November 5, 2001. The FERC approved the settlement on January 16, 2002.

Electricity. Under the Federal Power Act, the FERC has exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce by "public utilities." Public utilities that are subject to the FERC's jurisdiction must file rates with the FERC applicable to their wholesale sales or transmission of electricity in interstate commerce. All of Reliant Resources' generation subsidiaries sell power at wholesale and are public utilities under the Federal Power Act with the exception of two facilities in Texas, which are qualifying facilities and not regulated as public utilities. The facilities in our Texas generation business are located in ERCOT and therefore are not public utilities subject to the FERC's jurisdiction under the Federal Act. The FERC has authorized our public utility subsidiaries to sell electricity and related services at wholesale at market-based rates. In its orders authorizing market-based rates, the FERC also has granted these subsidiaries waivers of many of the accounting, record keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

The FERC's orders accepting the market-based rate schedules filed by our subsidiaries or their predecessors, as is customary with such orders, reserve the right to revoke or limit our market-based rate authority if the FERC subsequently determines that any of our affiliates possess excessive market power. If the FERC were to revoke or limit our market-based rate authority, we would have to file, and obtain the FERC's acceptance of, cost-based rate schedules for all or some of our sales. In addition, the loss of market-based rate authority could subject us to the accounting, record keeping and reporting requirements that the FERC imposes on public utilities with cost-based rate schedules. Sales from our Electric Operations business segment are not subject to FERC jurisdiction because ERCOT is not connected to a national grid.

The FERC issued Order No. 2000 in December 1999. Order No. 2000, which applies to all FERC jurisdictional transmission providers, describes the FERC's intention to promote the establishment of large RTOs and sets forth the minimum characteristics and functions of RTOs. Among the basic minimum characteristics are that the RTOs must be independent of market participants and must be of sufficient scope and geographical configuration. Order No. 2000 also encourages RTOs to work with each other to minimize or eliminate "seams" issues between RTOs that operate as barriers to inter-regional transactions. The FERC's goal is to encourage the growth of a robust competitive wholesale market for electricity. Although jurisdictional transmission providers are not required to join RTOs, they are encouraged to do so. Under Order No. 2000, RTOs were to be operational by December 15, 2001. However, because RTO development was in different stages in different regions of the country, the FERC issued an order on November 7, 2001 extending

the deadline until it resolves issues relating to geographic scope and governance of qualifying RTOs across the country and issues relating to business and procedural needs. For organizations to accomplish the functions of Order No. 2000, the FERC is taking steps to create business standards and protocols to facilitate RTO formation. However, there can be no assurance that the FERC's goals will be achieved. Also there is considerable state-level resistance in some regions, including regions in which we operate, to the formation of RTOs. At least 14 separate organizations, covering the substantial majority of all the FERC jurisdictional transmission providers, are in various stages of organization and have made at least preliminary filings with the FERC. Our T&D Utility is not subject to the FERC's jurisdiction, except with respect to certain high voltage, direct current ties linking ERCOT to the Southwest Power Pool, and therefore does not have to join an RTO.

Trading and Marketing Our domestic electric trading and marketing operations outside of ERCOT are also subject to the FERC's jurisdiction under the Federal Power Act. As a gas marketer, we make sales of natural gas in interstate commerce at wholesale pursuant to a blanket certificate issued by the FERC, but the FERC does not otherwise regulate the rates, terms or conditions of these gas sales. We also have subsidiaries that are "public utilities" under the Federal Power Act, and their wholesale sales of electricity in interstate commerce are subject to FERC-filed rate schedules that authorize them to make sales at negotiated, market-based rates.

In authorizing market-based rates for various of our subsidiaries, the FERC has imposed some restrictions on these entities' transactions with Reliant Energy HL&P, including a prohibition on the receipt of goods or services on a preferential basis. The FERC also has imposed restrictions on natural gas transactions between Reliant Resources' public utility subsidiaries and Reliant Energy's natural gas pipeline subsidiaries to preclude any preferential treatment. Similar restrictions apply to transactions between Reliant Resources and Reliant Energy HL&P under Texas utility regulatory laws.

Hydroelectric Facilities. The majority of our generating facilities located in the state of New York are hydroelectric facilities, many of which are subject to the FERC's exclusive authority under the Federal Power Act to license non-federal hydroelectric projects located on navigable waterways and federal lands. These FERC licenses must be renewed periodically and can include conditions on operation of the project at issue.

State and Local Regulations

Texas

Electric Operations — The Texas Electric Restructuring Law. In June 1999, the Texas legislature adopted the Texas Electric Restructuring Law, which substantially amended the regulatory structure governing electric utilities in Texas in order to allow and encourage retail competition. Retail pilot projects allowing competition for up to 5% of each utility's load in all customer classes began in August 2001, and retail electric competition for all other customers began in January 2002.

The Texas Electric Restructuring Law required electric utilities in Texas to restructure their businesses in order to separate power generation, transmission and distribution, and retail electric sales activities into three different units, whether commonly or separately owned. As a result of the Texas Electric Restructuring Law, retail sales of electricity to residential, commercial and industrial customers must now be made by "retail electric providers." Generally, the retail electric providers that have been certified by the Texas Utility Commission obtain electricity from power generation companies, exempt wholesale generators and other generating entities at unregulated rates, sell electricity at generally unregulated rates to their retail customers and pay the transmission and distribution utility a regulated tariff rate for delivering the electricity to their customers. For additional information regarding these transmission and distribution utility tariff rates, please read "— Electric Operations — Rate Case" in Item 1 of this Form 10-K. Retail electric providers are not permitted to own or operate generation assets and, as a general rule, their prices are not subject to traditional cost-of-service rate regulation. Retail electric providers that are affiliates of, or successors in interest to, electric utilities may compete substantially statewide for these sales, but prices they may charge to residential and small commercial customers within the affiliated electric utility's certificated service territory are subject to a fixed, specified price set by the Texas Utility Commission at the outset of retail competition (price to beat) that is subject to potential adjustments up to two times per year. All of our retail activities, including

activities conducted by retail electric providers in Texas, are now conducted by Reliant Resources and its subsidiaries.

Wholesale power generators will continue to sell electric energy to purchasers, including retail electric providers, at unregulated rates. To facilitate a competitive market, each power generator affiliated with a transmission and distribution utility is required to sell at auction 15% of the output of its installed generating capacity. This auction obligation continues until January 1, 2007, unless the Texas Utility Commission determines before that date that at least 40% of the quantity of electric power consumed in 2000 by residential and small commercial customers in the affiliated transmission and distribution utility's service area is being served by retail electric providers not affiliated with the incumbent utility. An affiliated retail electric provider may not purchase capacity sold by its affiliated power generation company in the state mandated capacity auction. For additional information regarding the state mandated auctions, please read "Electric Operations — Generation — State Mandated Capacity Auctions" in Item 1 of this Form 10-K and Note 4(a) to our consolidated financial statements.

Municipally-owned utilities and electric cooperatives have the option to open their markets to retail competition any time after January 1, 2002. However, until a municipally-owned utility or electric cooperative adopts a resolution opting to open its market to retail competition, it may not offer electric energy at unregulated prices to retail customers outside its service area. In November 2001, Nueces Electric Cooperative and San Patricio Electric Cooperative received Texas Utility Commission approval of required filings necessary to open their markets to retail competition. Some large Texas cities, including San Antonio and Austin, are served by municipally-owned utilities that have not announced when or if they will open their markets to competition.

In December 2001, the Texas Utility Commission established the price to beat which the retail electric providers operated under Reliant Resources are required to charge their residential and small commercial customers for electricity sales in Reliant Energy HL&P's service territory. The price to beat was set at a level resulting in an estimated 17% reduction to pre-existing rates for residential customers and an estimated 22% reduction to pre-existing rates for small commercial customers.

New, unaffiliated retail electric providers that enter a particular market may sell electricity to residential and small commercial customers at any price, including a price below the price to beat. By allowing non-affiliated retail electric providers to provide retail electric service to customers in an electric utility's traditional service territory at any price, including a price below the price to beat, the Texas Electric Restructuring Law is designed to encourage competition among retail electric providers. Affiliated retail electric providers will not be permitted to sell electricity to residential and small commercial customers in the transmission and distribution utility's traditional service territory at a price other than the price to beat until January 1, 2005, unless before that date the Texas Utility Commission determines that 40% or more of the amount of electric power that was consumed in 2000 by the relevant class of customers in the certificated service area of the affiliated transmission and distribution utility is committed to be served by other retail electric providers. In addition, the Texas Electric Restructuring Law requires the affiliated retail electric provider to make the price to beat available to residential and small commercial customers in the traditional service area of the related incumbent utility through January 1, 2007. The price to beat only applies to electric services provided to residential and small commercial customers (*i.e.* customers with an aggregate peak demand at or below one MW). Electric services provided to large commercial, industrial and institutional customers (*i.e.* customers with an aggregate peak demand of greater than one MW), whether by the affiliated retail electric provider or a non-affiliated retail electric provider, may be provided at any negotiated price.

The Texas Utility Commission's regulations allow an affiliated retail electric provider to adjust the wholesale energy supply cost component or "fuel factor" included in its price to beat based on a percentage change in the price of natural gas. The fuel factor included in our price to beat was initially set by the Texas Utility Commission at the then average forward 12 month gas price strip of approximately $3.11/MMBtu. In addition, the affiliated retail electric provider may also request an adjustment as a result of changes in its price of purchased energy. In such a request, the affiliated retail electric provider may adjust the fuel factor to the extent necessary to restore the amount of headroom that existed at the time the initial price to beat fuel factor

was set by the Texas Utility Commission. An affiliated retail electric provider may request that its price to beat be adjusted twice a year. Currently, we cannot estimate with any certainty the magnitude and timing of the adjustments required, if any, and the eventual impact of such adjustments on headroom. To the extent that the adjustments are not received on a timely basis, our Retail Energy business segment's results of operations may be adversely affected. Based on forward gas prices at the end of March 2002, the retail electric providers operated under Reliant Resources estimate they would be able to increase their price to beat by between approximately 4-5%.

The Texas Electric Restructuring Law requires the affiliated retail electric provider to reconcile and credit to the affiliated transmission and distribution utility in early 2004 any positive difference between the price to beat, reduced by a specified delivery charge, and the prevailing market price of electricity unless the Texas Utility Commission determines that, on or prior to January 1, 2004, 40% or more of the amount of electric power that was consumed in 2000 by residential or small commercial customers, as applicable, within the affiliated transmission and distribution utility's traditional service territory is committed to be served by other non-affiliated retail electric providers. If the 40% test is not met, the reconciliation and credit will be in the form of a payment from Reliant Resources to CenterPoint Energy, not to exceed $150 per customer. For additional information regarding this payment, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Reliant Resources-unregulated businesses — "Clawback" Payment to Reliant Energy" in Item 7 of this Form 10-K.

The Texas Electric Restructuring Law requires the Texas Utility Commission to designate retail electric providers as POLRs in areas of the state in which retail competition is in effect. A POLR is required to offer a standard retail electric service package for each class of customers designated by the Texas Utility Commission at a fixed, nondiscountable rate approved by the Texas Utility Commission, and is required to provide the service package to any requesting retail customer in the territory for which it is the POLR. In the event that another retail electric provider fails to serve any or all of its customers, the POLR is required to offer that customer the standard retail service package for that customer class with no interruption of service. For additional information regarding the obligations of StarEn Power, a subsidiary of Reliant Resources, as a POLR, and regarding the Texas retail market framework in general, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations" in Item 7 of this Form 10-K.

Electric Operations — Rate Case. On October 3, 2001, the Texas Utility Commission issued an order setting the rates to be charged by the T&D Utility for delivery of electricity beginning in January 2002. The order resulted from a March 31, 2000 filing (Wires Case) with the Texas Utility Commission as required by the Texas Electric Restructuring Law. The Wires Case set the regulated rates for the T&D Utility to be effective when electric competition began. This regulated wires rate, or non-bypassable delivery charge, includes the transmission and distribution rate, a system benefit fund fee, a nuclear decommissioning fund charge, a municipal franchise fee and a transition charge associated with securitization of regulatory assets. In addition, we are required to make a final fuel reconciliation filing under the terms of the Texas Electric Restructuring Law on or before July 1, 2002. For additional information regarding the effects of the Texas Utility Commission's October 3, 2001 order, please read Note 4 to our consolidated financial statements.

Electric Operations — Fuel Filings. For additional information regarding the fuel filings of our Texas generation business for the recovery of under-recovered fuel costs, please read Note 4(c) to our consolidated financial statements.

Electric Operations — Stranded Costs and Regulatory Assets. The Texas Electric Restructuring Law provides for the recovery of stranded costs and regulatory assets resulting from the unbundling of generation facilities and the related onset of retail competition. Stranded costs include the positive excess of the regulatory net book value of generation assets over the market value of the assets, taking into account a utility's generation assets, any above-market purchased power costs and any deferred debits relating to a utility's mandatory discontinuance of the application of certain accounting standards for generation-related assets. The Texas Electric Restructuring Law provides several alternatives for the determination of stranded costs, and pursuant to the master separation agreement we have agreed to use the "partial stock valuation"

methodology under which we plan to cause Texas Genco to either issue and sell in an initial public offering or to distribute to our shareholders no more than 20% of Texas Genco's common stock. Under this methodology, the Texas Utility Commission will employ the trading price of the stock on a national exchange over a defined period to arrive at the market value of Texas Genco in order to assess our stranded costs in a proceeding that we will file in 2004. In accordance with the Texas Electric Restructuring Law, beginning on January 1, 2002, and ending when the true-up proceeding is completed in January 2004, any difference between market power prices received in the generation capacity auction and the Texas Utility Commission's earlier estimates of those market prices will be included in the 2004 stranded cost true-up. This component of the true-up is intended to ensure that neither the customers nor Reliant Energy is disadvantaged economically as a result of the two-year transition period by providing this pricing structure. For more information about stranded costs, please read "Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Electric Operations — Generation" in Item 7 of this Form 10-K and Note 4(a) to our consolidated financial statements.

Our regulatory assets include the Texas generation business-related portion of the amount reported by us in our 1998 Form 10-K as "regulatory assets and liabilities," offset by the applicable portion of generation-related investment tax credits permitted under the Internal Revenue Code. Pursuant to a financing order issued by the Texas Utility Commission, we issued, through an indirect wholly owned subsidiary, $749 million aggregate principal amount of transition bonds in October 2001 and used the proceeds to reduce our recoverable regulatory assets by repaying other indebtedness. For more information about the transition bonds and recovery of regulatory assets, please read Note 4(a) to our consolidated financial statements.

We will make a filing in January 2004 in a true-up proceeding provided for by the Texas Electric Restructuring Law. The purpose of this proceeding will be to quantify and reconcile the amount of stranded costs, differences in the capacity auction prices and Texas Utility Commission estimates, unreconciled fuel costs and other regulatory assets associated with our Texas generation business not previously securitized by the transition bonds. We will be required to establish and support the amounts of these costs in order to recover them. For more information about the true-up proceeding, please read Note 4(a) to our consolidated financial statements.

Electric Operations — Other. Currently, the T&D Utility conducts its electric utility operations under a certificate of convenience and necessity granted by the Texas Utility Commission. The certificate of convenience and necessity covers the present service area and facilities of our Electric Operations business segment. In addition, the T&D Utility holds non-exclusive franchises from the incorporated municipalities in the service territory of our Electric Operations business segment. These franchises give the T&D Utility the right to operate its transmission and distribution system within the streets and public ways of these municipalities for the purpose of delivering electric service to the municipality, its residents and businesses. None of these franchises expires before 2007.

Other States

Natural Gas Distribution. In almost all communities in which our Natural Gas Distribution business segment provides service, RERC operates under franchises, certificates or licenses obtained from state and local authorities. The terms of the franchises, with various expiration dates, typically range from 10 to 30 years. None of our Natural Gas Distribution business segment's material franchises expire before 2005. We expect to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of our Natural Gas Distribution business segment's retail sales are subject to traditional cost-of-service regulation at rates regulated by the relevant state public service commissions and, in Texas, by the Texas Railroad Commission and municipalities we serve. For additional information regarding our ability to recover increased costs of natural gas from our customers, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Competitive and Other Factors Affecting RERC Operations — Natural Gas Distribution" in Item 7 of this Form 10-K.

On November 21, 2001, Arkla filed a rate case (Docket 01-243-U) with the Arkansas Public Service Commission seeking an increase in rates for its Arkansas customers of approximately $47 million on an annual basis. Arkla's last rate increase was authorized in 1995. In the rate filing, Arkla maintains that its rate base has grown by $183 million, and its operating expenses have increased from $93 million to $106 million on an annual basis and, therefore, Arkla's current rates for service to Arkansas customers do not provide a reasonable opportunity for Arkla to cover its operating costs and earn a fair return on its investment. A decision in the case is expected by the fourth quarter of 2002.

Nuclear Regulatory Commission

We are required by NRC regulations to estimate from time to time the amounts required to decommission our ownership share of the South Texas Project and are required to maintain funds to satisfy that obligation when the plant ultimately is decommissioned. We currently collect through our electric rates amounts calculated to provide sufficient funds at the time of decommissioning to discharge these obligations. Those funds are maintained in a nuclear decommissioning trust (Nuclear Decommissioning Trust). Under the Texas Electric Restructuring Law, funds for decommissioning nuclear facilities like the South Texas Project continue to be subject to cost of service rate regulation and are collected by the T&D Utility through a non-bypassable charge from transmission and distribution customers. Funds collected will be deposited into the Nuclear Decommissioning Trust.

When our Texas generation business is transferred to Texas Genco, we will transfer beneficial ownership in the Nuclear Decommissioning Trust to Texas Genco, as the licensee of the facility. In connection with that transfer, we have obtained a private letter ruling from the IRS to confirm that such funds will continue to receive tax treatment they currently hold following the transfer so long as Reliant Energy and its successor continue to own the controlling interest in Texas Genco. After the Restructuring, the T&D Utility will continue to collect amounts authorized under its rates for nuclear decommissioning and will pay the amounts collected to Texas Genco for deposit into the Nuclear Decommissioning Trust. Texas Genco will be responsible for complying with NRC requirements for decommissioning. Under the master separation agreement, however, the T&D Utility is obligated to collect from its customers amounts required to decommission the South Texas Project in the event the funds in the Nuclear Decommissioning Trust prove to be inadequate to satisfy the licensee's obligations, and the T&D Utility has agreed to indemnify Texas Genco from responsibility for additional amounts required even if they are not collected from customers.

While our current funding levels exceed NRC minimum requirements, no assurance can be given that the amounts held in trust will be adequate to cover the actual decommissioning costs of the South Texas Project. Such costs may vary because of changes in the assumed date of decommissioning and changes in regulatory requirements, technology and costs of labor, materials and waste burial. Nor can assurance be given that the current tax treatment accorded funds maintained in the Nuclear Decommissioning Trust or additional amounts deposited can be maintained if Reliant Resources exercises the Texas Genco Option.

For information regarding the NRC's regulation of nuclear decommissioning trust funds, please read Note 14(k) to our consolidated financial statements.

The Netherlands

Prior to the deregulation of the Dutch wholesale market in 2001, our European Energy business segment sold its generating output to a national production pool and, in return, received a standardized remuneration. The remuneration included fuel cost, return of and on capital and operation and maintenance expenses. Under a transitional agreement which expired in 2000, the non-fuel portion of this amount was fixed during the period 1997 through 2000. For additional information, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our European Energy Operations — Competition in the European Market" and "— Deregulation of the Dutch Market" in Item 7 of this Form 10-K.

In 2001, the wholesale energy market of our European Energy business segment's primary market in the Netherlands was opened to competition. Our European Energy business segment continues to be subject to

regulation by a number of national and European regulatory agencies and regulations relating to the environment, labor, tax and other matters. For example, our European Energy business segment's operations are subject to the regulation of Dutch and European Community anti-trust authorities, who have extensive authority to investigate and prosecute violations by energy companies of anti-monopolistic and price-fixing regulations. In addition, our European Energy business segment must also comply with various national and regional grid codes and other regulations establishing access to transmission systems. Many of the significant suppliers and customers of our European Energy business segment are subject to continued regulation by various energy regulatory bodies that have the authority to establish tariffs for such entities. The impact of regulations on these entities has an indirect impact on our European Energy business segment.

In some European countries, it is uncertain to what extent companies trading in energy, fuel and other commodities (physical and financial) might be deemed subject to regulation as brokers and dealers under local securities laws. To the extent that its operations are deemed subject to these laws, our European Energy business segment could become subject to minimum capitalization, licensing and reporting requirements similar to those which exist for securities broker and dealer firms. Although our European Energy business segment believes that its operations are currently outside the scope of such regulations, no assurance can be given as to the future positions of these regulatory agencies regarding the applicability of these regulations to our European Energy business segment's operations.

ENVIRONMENTAL MATTERS

General Environmental Issues

We are subject to numerous federal, state and local requirements relating to the protection of the environment and the safety and health of personnel and the public. These requirements relate to a broad range of our activities, including the discharge of pollutants into air, water, and soil, the proper handling of solid, hazardous, and toxic materials and waste, noise, and safety and health standards applicable to the workplace. In order to comply with these requirements, we will spend substantial amounts from time to time to construct, modify and retrofit equipment, acquire air emission allowances for operation of our facilities, and to clean up or decommission disposal or fuel storage areas and other locations as necessary.

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

We anticipate investing up to $532 million in capital and other special project expenditures between 2002 and 2006 for environmental compliance, $397 million of which is comprised of projected expenditures for CenterPoint Energy and its subsidiaries after the Distribution and $135 million of which is comprised of projected expenditures for Reliant Resources and its subsidiaries after the Distribution. In addition, environmental capital expenditures for the recently acquired Orion Power assets over this period are estimated to be $241 million. We are currently reviewing these estimates. For additional information regarding environmental expenditures, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Environmental Expenditures" in Item 7 of this Form 10-K and Note 14(f) to our consolidated financial statements.

Air Emissions

As part of the 1990 amendments to the Federal Clean Air Act, requirements and schedules for compliance were developed for attainment of health-based standards. As part of this process, standards for the emission of NOx, a product of the combustion process associated with power generation and natural gas compression, are being developed or have been finalized. The standards require reduction of emissions from our power generating units in the United States and some of our natural gas compression facilities. We believe the reductions will require substantial expenditures in the years 2002 through 2004, with possible additional expenditures after that for our facilities in Texas. The Texas Electric Restructuring Law provides for stranded cost recovery of costs incurred before May 1, 2003 to achieve the NOx reduction requirements. The post-2004

requirements in Texas are currently being litigated, and the outcome of the litigation cannot be predicted at this time. Our facilities in the Netherlands were in compliance with applicable Dutch NOx emission standards through the year 2001. New NOx reduction targets have recently been adopted in the Netherlands which will require a 50% reduction in NOx emissions from 2000 levels by 2010. The reductions may be achieved through the installation of emission control equipment or through the participation in a planned market-based emission trading system. We currently believe that our Dutch facilities will not be required to install NOx controls or purchase emission credits until the 2005 through 2006 time period. Projected emission control costs are estimated to be approximately $30 million, although this investment may be offset to some extent or delayed if a market-based trading program develops.

The Environmental Protection Agency (EPA) has announced its determination to regulate hazardous air pollutants (HAPs), including mercury, from coal-fired and oil-fired steam electric generating units under Section 112 of the Clean Air Act. The EPA plans to develop maximum achievable control technology (MACT) standards for these types of units. The rulemaking for coal and oil-fired steam electric generating units must be completed by December 2004. Compliance with the rules will be required within three years thereafter. The MACT standards that will be applicable to the units cannot be predicted at this time and may adversely impact our results of operations. In addition, a request for reconsideration of the EPA's decision to impose MACT standards has been filed with the EPA. We cannot predict the outcome of the request.

In 1998, the United States became a signatory to the United Nations Framework Convention on Climate Change (Kyoto Protocol). The Kyoto Protocol calls for developed nations to reduce their emissions of greenhouse gases. Carbon dioxide, which is a major byproduct of the combustion of fossil fuel, is considered to be a greenhouse gas. If the United States Senate ultimately ratifies the Kyoto Protocol, any resulting limitations on power plant carbon dioxide emissions could have a material adverse impact on all fossil fuel fired facilities, including those belonging to us. The European Union, of which the Netherlands is a member, has adopted the Kyoto Protocol as the goal for greenhouse gas emission targets. We expect REPGB, our Dutch subsidiary, through use of "green fuels" and efficiency improvements, will be able to meet its portion of the target reductions.

The EPA is conducting a nationwide investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Clean Air Act. Specifically, the EPA and the United States Department of Justice have initiated formal enforcement actions and litigation against several other utility companies that operate these stations, alleging that these companies modified their facilities without proper pre-construction permit authority. Since June 1998, six of our coal-fired facilities operated through Reliant Resources have received requests for information related to work activities conducted at those sites, as have two of our recently acquired Orion Power facilities. The EPA has not filed an enforcement action or initiated litigation in connection with these facilities at this time. Nevertheless, any litigation, if pursued successfully by the EPA, could accelerate the timing of emission reductions currently contemplated for the facilities and result in the imposition of penalties.

In February 2001, the United States Supreme Court upheld a previously adopted EPA ambient air quality standards for fine particulate matter and ozone. While attaining these new standards may ultimately require expenditures for air quality control system upgrades for our facilities, regulations addressing affected sources and required controls are not expected until after 2005. Consequently, it is not possible to determine the impact on our operations at this time.

Multi-pollutant air emission initiative. On February 14, 2002, the White House announced its "Clear Skies Initiative." The proposal is aimed at long term reductions of multiple pollutants produced from fossil fuel-fired power plants. Reductions averaging 70% are targeted for sulfur dioxide (SO2), NOx, and mercury. In addition, a voluntary program for greenhouse gas emissions is proposed as an alternative to the Kyoto Protocol discussed above. The implementation of the initiative, if approved by the United States Congress, would be a market-based program beginning in 2008 and phased full compliance by 2018. Fossil fuel-fired power plants in the United States would be affected by the adoption of this program, or other legislation currently pending in the United States Congress addressing similar issues. Such programs would require

compliance to be achieved by the installation of pollution controls, the purchase of emission allowances or curtailment of operations.

Water Issues

In July 2000, the EPA issued final rules for the implementation of the Total Maximum Daily Load program of the Clean Water Act (TMDL). The goal of the TMDL rules is to establish, over the next 15 years, the maximum amounts of various pollutants that can be discharged into waterways while keeping those waterways in compliance with water quality standards. The establishment of TMDL values may eventually result in more stringent discharge limits in each facility's discharge permit. Such limits may require our facilities to install additional water treatment, modify operational practices or implement other wastewater control measures. Certain members of the United States Congress have expressed concern to the EPA about the TMDL program and the EPA, in October 2001, extended the effective date of the regulation until April 2003.

In November 2001, the EPA promulgated rules that impose additional technology based requirements on new cooling water intake structures. Proposed rules for existing intake structures have also been issued. It is not known at this time what requirements the final rules for existing intake structures will impose and whether our existing intake structures will require modification as a result of such requirements. The process by which the intake structure rules were written was contentious and litigation is expected. Court action in response to this expected litigation could result in unforeseen changes in the requirements.

A number of efforts are under way within the EPA to evaluate water quality criteria for parameters associated with the by-products of fossil fuel combustion. These parameters include arsenic, mercury and selenium. Significant changes in these criteria could impact station discharge limits and could require our facilities to install additional water treatment equipment. The impact on us as a result of these initiatives is unknown at this time.

Liability for Preexisting Conditions and Remediation

Under the purchase agreements between Sithe Energies and Reliant Energy Power Generation, Inc. (REPG), a subsidiary of Reliant Resources, relating to some of our Northeast regional facilities, and in the transaction with Orion Power, Reliant Resources, with a few exceptions, assumed liability for preexisting conditions, including some ongoing remediations at the electric generating stations. Funds for carrying out any identified actions have been included in our planning for future requirements, and we are not currently aware of any environmental condition at any of our facilities that we expect to have a material adverse effect on our financial position, results of operation or cash flows.

A prior owner of one of our Northeast facilities entered into a Consent Order Agreement with the Pennsylvania Department of Environmental Protection (PaDEP) to remediate a coal refuse pile on the property of the facility. We expect the remediation will cost between $10 million and $15 million. Under the acquisition agreements between Sithe Energies and GPU, Inc. (GPU) relating to some of our Northeast regional facilities, GPU has agreed to retain responsibility for up to $6 million of environmental liabilities associated with the coal refuse site at this facility. We will be responsible for any amounts in excess of that $6 million. In August 2000 we signed a modified consent order that committed us to complete the remediation work no later than November 2004. In addition to the coal refuse site at this facility, we had liabilities associated with six future ash disposal site closures and six current site investigations and environmental remediations. We expect to pay approximately $16 million over the next five years to monitor and remediate these sites.

Under the New Jersey Industrial Site Recovery Act (ISRA), owners and operators of industrial properties are responsible for performing all necessary remediation at the facility prior to the closing of a facility and the termination of operations, or undertaking actions that ensure that the property will be remediated after the closing of a facility and the termination of operations. In connection with the acquisition of facilities from Sithe Energies, Reliant Resources has agreed to take responsibility for any costs under ISRA relating to the four New Jersey properties they purchased. They estimate that the costs to fulfill their

obligations under ISRA will be approximately $10 million. However, these remedial activities are still in the early stages. Following further investigation the scope of the necessary remedial work could increase, and we could, as a result, incur greater costs.

One of our Florida generation facilities operated through Reliant Resources discharges wastewater to percolation ponds which in turn, percolate into the groundwater. Elevated levels of vanadium and sodium have been detected in groundwater monitoring wells. A noncompliance letter has been received from the Florida Department of Environmental Protection. A study to evaluate the cause of the elevated constituents has been undertaken. At this time, if remediation is required, the cost, if any, is not anticipated to be material.

As a result of their age, many of our facilities contain significant amounts of asbestos insulation, other asbestos containing materials, as well as lead-based paint. Existing state and federal rules require the proper management and disposal of these potentially toxic materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations, and removal and abatement of asbestos containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself. We have planned for the proper management, abatement and disposal of asbestos and lead-based paint at our facilities in our financial planning.

Manufactured Gas Plant Sites. RERC and its predecessors operated a manufactured gas plant until 1960 adjacent to the Mississippi River in Minnesota formerly known as Minneapolis Gas Works. RERC has substantially completed remediation of the main site other than ongoing water monitoring and treatment. The manufactured gas was stored in separate holders. RERC is negotiating cleanup of one such holder. There are six other former manufactured gas plant sites in the Minnesota service territory. Remediation has been completed on one site. Of the remaining five sites, RERC believes that two were neither owned nor operated by RERC. RERC believes it has no liability with respect to the sites we neither owned nor operated.

At December 31, 2000 and 2001, RERC had accrued $18 million and $23 million, respectively, for remediation of the Minnesota sites. At December 31, 2001, the estimated range of possible remediation costs was $11 million to $49 million. The cost estimates of the Minneapolis Gas Works site are based on studies of that site. The remediation costs for the other sites are based on industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites remediated, the participation of other potentially responsible parties, if any, and the remediation methods used.

Issues relating to the identification and remediation of manufactured gas plants are common in the natural gas distribution industry. RERC has received notices from the United States Environmental Protection Agency and others regarding its status as a potentially responsible party for other sites. Based on current information, RERC has not been able to quantify a range of environmental expenditures for potential remediation expenditures with respect to other manufactured gas plant sites.

Hydrocarbon Contamination. In August 2001, a number of Louisiana residents who live near the Wilcox Aquifer filed suit against RERC Corp., Reliant Energy Pipeline Services, Inc., other Reliant Energy entities and third parties (Docket No. 460, 916-Div. "B"), in the 1st Judicial District Court, Caddo Parish, Louisiana. The suit alleges that we and the other defendants allowed or caused hydrocarbon or chemical contamination of the Wilcox Aquifer, which lies beneath property owned or leased by the defendants and is the sole or primary drinking water aquifer in the area. The quantity of monetary damages sought is unspecified. For additional information regarding this suit and the remediation of the site, please read note 14(f) to our consolidated financial statements.

Other Minnesota Matters. At December 31, 2000 and 2001, RERC had recorded accruals of $4 million and $5 million, respectively, for other environmental matters in Minnesota for which remediation may be required. At December 31, 2001, the estimated range of possible remediation costs was $4 million to $8 million.

Mercury Contamination

Like similar companies, our pipeline and natural gas 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 around the meters with elemental mercury. We have found this type of contamination in the past, and we have conducted remediation at sites found to be contaminated. Although we are not aware of additional specific sites, it is possible that other contaminated sites may exist and that remediation costs may be incurred for these sites. Although the total amount of these costs cannot be known at this time, based on our experience and that of others in the natural gas industry to date and on the current regulations regarding remediation of these sites, we believe that the cost of any remediation of these sites will not be material to our financial position, results of operations or cash flows. For additional information regarding environmental expenditures associated with mercury contamination, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting our Future Earnings — Environmental Expenditures — Water, Mercury and Other Expenditures" in Item 7 of this Form 10-K.

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

- The costs of responding to that release or threatened release; and
- The restoration of natural resources damaged by any such release.

We are not aware of any liabilities under CERCLA that would have a material adverse effect on us, our financial position, results of operations or cash flows.

European Energy

European and Dutch environmental laws are among the most stringent in the industrial world. Under Dutch environmental laws, an environmental permit is required to be maintained for each generation facility. As is customary in Dutch practice, our European Energy business segment has, together with other industry participants, entered into various contractual agreements with the national government on specific environmental matters, including the reduction of the use of coal and other fossil fuel. The environmental laws also address public safety. We believe our European Energy business segment holds all necessary authorizations and approvals for its current operations.

The European Union, of which the Netherlands is a member, adopted the Kyoto Protocol as the goal for greenhouse gas emission targets. For further discussion of the protocol, please read "— Air Emissions." We believe our European Energy business segment will meet its current portion of target reductions because of its use of "green fuels" and efficiency improvements to its facilities.

NOx reduction targets will require a 50% reduction in NOx emissions from 2000 levels by 2010. The reductions may be achieved through the installation of emission control equipment or through the participation in a planned market-based emission trading system. Our European facilities are in compliance with current and applicable Dutch NOx emission standards. Based on current factors, we believe that our European facilities will not be required to install NOx controls or purchase emission credits until the 2005-2006 time period.

We estimate that we will spend approximately $30 million in emission control and other environmental costs associated with our European Energy business segment for the period 2002 through 2006. In addition, we expect to spend approximately $18 million in asbestos and other environmental remediation programs during this period.

Other

We have been named, along with numerous others, as a defendant in a number of lawsuits filed by a large number of individuals who claim injury due to exposure to asbestos while working at sites along the Texas Gulf Coast. Most of these claimants have been workers who participated in construction of various industrial

facilities, including power plants, and some of the claimants have worked at locations owned by us. We anticipate that additional claims like those received may be asserted in the future, and we intend to continue our practice of vigorously contesting claims that we do not consider to have merit. Although their ultimate outcome cannot be predicted at this time, we do not believe, based on our experience to date, that these matters, either individually or in the aggregate, will have a material adverse effect on our financial position, results of operations or cash flows.

EMPLOYEES

As of December 31, 2001, we had 16,958 full-time employees. The following table sets forth the number of our employees by business segment as of December 31, 2001:

Business Segment	Number
Electric Operations	5,741
Natural Gas Distribution	4,943
Pipelines and Gathering	614
Wholesale Energy	2,395
European Energy	916
Retail Energy	1,202
Latin America	398
Other Operations	749
Total	16,958

The number of our employees who were represented by unions or other collective bargaining groups as of December 31, 2001 include (i) Electric Operations, 2,735; (ii) Natural Gas Distribution, 1,542; (iii) Wholesale Energy, 810; and (iv) European Energy, 745.

EXECUTIVE OFFICERS OF RELIANT ENERGY
(As of March 1, 2002)

Name	Age	Officer Since	Present Position
R. Steve Letbetter(1)	53	1978	Chairman, President, Chief Executive Officer and Director
Robert W. Harvey(1)	46	1999	Vice Chairman
David M. McClanahan(2)	52	1986	Vice Chairman, President and Chief Operating Officer, Reliant Energy Regulated Group
Stephen W. Naeve(1)	54	1988	Vice Chairman and Chief Financial Officer
Joe Bob Perkins(1)	41	1996	President and Chief Operating Officer, Reliant Energy Wholesale Group
Hugh Rice Kelly(1)	59	1984	Executive Vice President, General Counsel and Corporate Secretary
Mary P. Ricciardello(1)	46	1993	Senior Vice President and Chief Accounting Officer

(1) Effective as of the Restructuring, these individuals will continue to serve in the indicated capacities for CenterPoint Energy. Effective as of the Distribution, these individuals will resign their positions with CenterPoint Energy, except that Mr. Letbetter will continue to serve as non-executive Chairman of the CenterPoint Energy Board of Directors.

(2) Effective as of the Distribution, Mr. McClanahan will become President and Chief Executive Officer of CenterPoint Energy.

Mr. Letbetter has served as Chairman of Reliant Energy since January 2000 and as President and Chief Executive Officer of Reliant Energy since June 1999. He has been a director of Reliant Energy since 1995. He has served in various executive officer capacities with Reliant Energy since 1978.

Mr. Harvey has served as Vice Chairman of Reliant Energy since June 1999. Prior to joining Reliant Energy, he served as a director in the Houston office of McKinsey & Company, Inc.

Mr. Naeve has served as Vice Chairman of Reliant Energy since June 1999 and as Chief Financial Officer of Reliant Energy since 1997. Between 1997 and 1999, he served as Executive Vice President and Chief Financial Officer of Reliant Energy. He has served in various executive officer capacities with Reliant Energy since 1988.

Mr. Perkins has served as President and Chief Operating Officer, Reliant Energy Wholesale Group, and as President and Chief Operating Officer, Reliant Energy Power Generation, Inc. since 1998. In 1998, Mr. Perkins served as President and Chief Operating Officer of the Reliant Energy Power Generation Group. Between 1996 and 1998, Mr. Perkins served as Vice President — Corporate Planning and Development.

Mr. Kelly has served as Executive Vice President, General Counsel and Corporate Secretary of Reliant Energy since 1997. Between 1984 and 1997, he served as Senior Vice President, General Counsel and Corporate Secretary of Reliant Energy.

Ms. Ricciardello has served as Chief Accounting Officer of Reliant Energy since June 2000 and as Senior Vice President since June 1999. Between 1999 and 2000, she served as Senior Vice President and Comptroller of Reliant Energy. She also served as Vice President and Comptroller of Reliant Energy from 1996 to 1999. She has served in various executive officer capacities with Reliant Energy since 1993.

We currently expect that at the time of the Distribution, David M. McClanahan will become President and Chief Executive Officer of CenterPoint Energy. Mr. McClanahan, who is 52 years old, has served as Vice Chairman of Reliant Energy since October 2000 and as President and Chief Operating Officer of Reliant Energy's Regulated Group since 1999. He served as President and Chief Operating Officer of Reliant Energy HL&P from 1997 to 1999. He has served in various executive officer capacities with Reliant Energy since 1986.

Item 2. *Properties*

Character of Ownership

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

Substantially all of the real estate, electric distribution system properties, buildings and franchises owned directly by Reliant Energy (excluding real estate and other properties of subsidiaries of Reliant Energy) are subject to a lien created under a Mortgage and Deed of Trust dated as of November 1, 1944 (as supplemented, Mortgage) between Reliant Energy and South Texas Commercial National Bank of Houston (JP Morgan Chase Bank, as Successor Trustee). The lien of the Mortgage excludes cash, stock in subsidiaries and certain other assets. Additionally, properties owned by subsidiaries of Reliant Energy are subject to liens of creditors of the respective subsidiaries. We believe we have satisfactory title to our facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions which, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Electric Operations

For information regarding the properties of our Electric Operations business segment, please read "Electric Operations" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

Natural Gas Distribution

For information regarding the properties of our Natural Gas Distribution business segment, please read "Natural Gas Distribution" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

Pipelines and Gathering

For information regarding the properties of our Pipelines and Gathering business segment, please read "Pipelines and Gathering" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

Wholesale Energy

For information regarding the properties of our Wholesale Energy business segment, please read "Wholesale Energy" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

European Energy

For information regarding the properties of our European Energy business segment, please read "European Energy" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

Retail Energy

For information regarding the properties of our Retail Energy business segment, please read "Retail Energy" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

Latin America

For information regarding the properties of our Latin America business segment, please read "Latin America" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

Other Operations

For information regarding the properties of our Other Operations business segment, please read "Other Operations" in Item 1 of this Form 10-K, which information is incorporated herein by reference.

Item 3. ***Legal Proceedings***

For a description of certain legal and regulatory proceedings affecting us, see Notes 4, 14(f), 14(g) and 21 to our consolidated financial statements, which notes are incorporated herein by reference.

Restatement of Second and Third Quarter 2001 Results of Operations

On February 5, 2002, Reliant Energy announced that it was restating its earnings for the second and third quarters of 2001. As more fully described in Reliant Energy's March 15, 2002 Current Report on Form 8-K, the restatement related to a correction in accounting treatment for a series of four structured transactions that were inappropriately accounted for by Reliant Resources as cash flow hedges for the period of May 2001 through September 2001, rather than as derivatives with changes in fair value recognized through the income statement. Each structured transaction involved a series of forward contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002 or 2003.

At the time of the public announcement of Reliant Energy's intention to restate its reporting of the structured transactions, the Audit Committees of each of the boards of directors of Reliant Energy and Reliant Resources instructed Reliant Resources to conduct an internal audit review to determine whether there were any other transactions included in the asset books as cash flow hedges that failed to meet the cash flow hedge requirements under Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting

for Derivative Instruments and Hedging Activities" (SFAS No. 133). This targeted internal audit review found no other similar transactions.

The Audit Committees also directed an internal investigation by outside legal counsel of the facts and circumstances leading to the restatement, which investigation has been completed. In connection with the restatement and related investigations, the Audit Committees have met eight times to hear and assess reports from the investigative counsel regarding its investigation and contacts with the staff of the SEC. To address the issues identified in the investigation process, the Audit Committees and management have begun analyzing and implementing remedial actions, including, among other things, changes in organizational structure and enhancement of internal controls and procedures.

On April 5, 2002, Reliant Resources was advised that the Staff of the Division of Enforcement of the SEC is conducting an informal inquiry into the facts and circumstances surrounding the restatement. Reliant Resources is cooperating with this inquiry. Before releasing its 2001 earnings, Reliant Energy received concurrence from the SEC's accounting staff on the accounting treatment of the restatement, which increased its earnings for the two quarters by a total of $107 million. At this time, we cannot predict the outcome of the SEC's inquiry. In addition, we cannot predict what effect the inquiry may have on our pending application to the SEC under the 1935 Act, which is required for our Restructuring. For more information about our Restructuring, please read "Our Business — Status of Business Separation" and "— Business Separation" in Item 1 of this Form 10-K.

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

A special meeting of our shareholders was held on December 17, 2001. At the meeting, our shareholders were asked to approve an Agreement and Plan of Merger, dated as of October 19, 2001, pursuant to which CenterPoint Energy would become the parent company of Reliant Energy and each outstanding share of Reliant Energy common stock would be automatically converted into one share of CenterPoint Energy common stock. The proposal to approve the Agreement and Plan of Merger was approved with 167,344,153 votes for, 56,529,357 votes against and 3,019,520 abstentions.

PART II

Item 5. *Market for Common Stock and Related Stockholder Matters*

As of April 8, 2002, our common stock was held of record by approximately 71,212 shareholders. Our common stock is listed on the New York and Chicago Stock Exchanges and is traded under the symbol "REI."

The following table sets forth the high and low sales prices of our common stock on the New York Stock Exchange composite tape during the periods indicated, as reported by *Bloomberg*, and the cash dividends declared in these periods. Cash dividends paid aggregated $1.50 per share in 2000 and 2001.

	Market Price		Dividend Declared Per Share
	High	Low	
2000			
First Quarter			$0.375
March 7		$19.88	
March 16	$24.38		
Second Quarter			$0.375
April 7		$22.56	
June 23	$29.81		
Third Quarter			$0.375
July 3		$29.81	
September 29	$46.50		
Fourth Quarter			$0.375
October 2	$48.19		
December 6		$38.06	
2001			
First Quarter			$0.375
January 11		$32.44	
March 30	$45.25		
Second Quarter			$0.375
May 1	$50.02		
June 26		$30.50	
Third Quarter			$0.375
July 10	$32.70		
September 27		$26.07	
Fourth Quarter			(1)
October 16	$28.88		
December 17		$23.64	

(1) The quarterly dividend of $0.375 per share normally declared in the fourth quarter for payment in the following first quarter was declared on February 8, 2002 and paid in March 2002.

The closing market price of our common stock on December 31, 2001 was $26.52 per share.

The amount of future cash dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable contractual restrictions and other factors that our board of directors considers relevant and will be declared at the discretion of the board of directors. No dividends are currently being paid to Reliant Energy by Reliant Resources, which may affect the ability of Reliant Energy to maintain its existing dividend levels pending completion of the Distribution.

After the consummation of the Restructuring, the declaration and payment of dividends by CenterPoint Energy will be at the discretion of its board of directors. CenterPoint Energy will not directly conduct any business operations from which it will derive revenues. Therefore, the payment and rate of future dividends on CenterPoint Energy common stock will depend primarily upon the earnings, financial condition and capital requirements of its subsidiaries. Following the Distribution, CenterPoint Energy will not be as large a company as Reliant Energy is today, and the earnings of the subsidiaries and assets that were transferred to Reliant Resources will not be available for the payment of dividends on the CenterPoint Energy common stock. As a result, the cash dividend per share of CenterPoint Energy common stock is expected to be reduced to a level that is consistent with both its earnings profile and the level of cash dividends of other predominately regulated utility businesses.

Subject to the availability of earnings, the needs of its businesses, and other applicable restrictions, upon becoming subsidiaries of CenterPoint Energy following the Restructuring, the T&D Utility and Texas Genco intend to make regular cash payments to CenterPoint Energy in the form of dividends or distributions on their stock or membership interests in amounts which would be sufficient to pay cash dividends on CenterPoint Energy common stock as described above and to pay operating expenses of CenterPoint Energy and for other purposes as the board of directors of CenterPoint Energy may determine. CenterPoint Energy expects that cash dividends will be declared and paid on approximately the same schedule as that now followed by us with respect to our common stock dividends.

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

The following table presents selected financial data with respect to our consolidated financial condition and consolidated results of operations and should be read in conjunction with our consolidated financial statements and the related notes in Item 8 of this Form 10-K.

Effective December 1, 2000 (Measurement Date), our board of directors approved a plan to dispose of our Latin America business segment through sales of its assets. Accordingly, in our 2000 consolidated financial statements, we reported the results of our Latin America business segment as discontinued operations in accordance with APB No. 30 for each of the three years in the period ended December 31, 2000. On December 20, 2001, negotiations for the sale of the remaining Latin America assets were terminated as a result of recent adverse economic developments in Argentina. We will continue to evaluate other options related to the future disposition of these assets. Accordingly, the Latin America business segment is no longer reported as discontinued operations. The related operating results and loss on disposal have been reclassified within the Statements of Consolidated Income for all periods into operating income with respect to consolidated subsidiaries and other income with respect to equity investments in unconsolidated subsidiaries as required for assets held for sale.

The selected financial data includes the financial statement effect of REMA since its acquisition in May 2000, REPGB since its acquisition in October 1999 and RERC since its acquisition in August 1997. These acquisitions were accounted for under the purchase method. Please read Note 3 to our consolidated financial statements for additional information regarding the REMA and REPGB acquisitions and Note 19 to our consolidated financial statements for additional information regarding our Latin America operations.

	Year Ended December 31,				
	1997(1)	1998(2)	1999(3)(7)	2000(4)(7)	2001(5)(7)
	(In millions, except per share amounts)				
Revenues	$ 6,786	$11,230	$13,794	$28,269	$40,810
Income (loss) before extraordinary items, cumulative effect of accounting change and preferred dividends	$ 421	$ (141)	$ 1,665	$ 440	$ 919
Extraordinary items, net of tax	—	—	(183)	7	—
Cumulative effect of accounting change, net of tax	—	—	—	—	61
Net income (loss) attributable to common stockholders(6)	$ 421	$ (141)	$ 1,482	$ 447	$ 980
Basic earnings (loss) per common share:					
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 1.66	$ (0.50)	$ 5.84	$ 1.54	$ 3.17
Extraordinary items, net of tax	—	—	(0.64)	0.03	—
Cumulative effect of accounting change, net of tax	—	—	—	—	0.21
Basic earnings (loss) per common share	$ 1.66	$ (0.50)	$ 5.20	$ 1.57	$ 3.38
Diluted earnings (loss) per common share:					
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 1.66	$ (0.50)	$ 5.82	$ 1.53	$ 3.14
Extraordinary items, net of tax	—	—	(0.64)	0.03	—
Cumulative effect of accounting change, net of tax	—	—	—	—	0.21
Diluted earnings (loss) per common share	$ 1.66	$ (0.50)	$ 5.18	$ 1.56	$ 3.35
Cash dividends paid per common share	$ 1.50	$ 1.50	$ 1.50	$ 1.50	$ 1.50
Dividend payout ratio	90%	—	26%	97%	47%
Return on average common equity	9.7%	(3.1)%	30.8%	8.3%	16.1%
Ratio of earnings to fixed charges	2.48	—	5.37	1.86	2.77
At year-end:					
Book value per common share	$ 17.28	$ 15.16	$ 18.70	$ 19.10	$ 22.77
Market price per common share	$ 26.75	$ 32.06	$ 22.88	$ 43.31	$ 26.52
Market price as a percent of book value	155%	211%	122%	227%	116%
Total assets	$18,268	$18,967	$26,456	$31,960	$30,681
Long-term debt obligations, including current maturities	$ 5,307	$ 7,049	$ 9,223	$ 6,619	$ 6,403
Trust preferred securities	$ 362	$ 342	$ 705	$ 705	$ 706
Cumulative preferred stock	$ 10	$ 10	$ 10	$ 10	$ —
Capitalization:					
Common stock equity	46%	37%	35%	43%	49%
Cumulative preferred stock	—	—	—	—	—
Trust preferred securities	3%	3%	5%	5%	5%
Long-term debt, including current maturities	51%	60%	60%	52%	46%
Business acquisitions	$ 1,423	$ 292	$ 1,060	$ 2,103	$ —
Capital expenditures	$ 328	$ 712	$ 1,166	$ 1,842	$ 2,053

(1) 1997 net income includes a non-cash, unrealized accounting loss on our indexed debt securities of $79 million (after-tax), or $0.31 loss per basic and diluted share. For additional information on the indexed debt securities, please read Note 8 to our consolidated financial statements.

(2) 1998 net income includes a non-cash, unrealized accounting loss on our indexed debt securities of $764 million (after-tax), or $2.69 loss per basic and diluted share. For additional information on the indexed debt securities, please read Note 8 to our consolidated financial statements. Fixed charges exceeded earnings by $179 million in 1998.

(3) 1999 net income includes an aggregate non-cash, unrealized accounting gain on our indexed debt securities and our Time Warner (now AOL Time Warner) investment, of $1.2 billion (after-tax), or $4.09 earnings per basic share and $4.08 earnings per diluted share. For additional information on the indexed debt securities and AOL Time Warner investment, please read Note 8 to our consolidated financial statements. The extraordinary item in 1999 is a loss related to an accounting impairment of certain generation related regulatory assets of our Electric Operations business segment. For additional information regarding the impairment, please read Note 4 to our consolidated financial statements.

(4) 2000 net income includes an aggregate non-cash accounting loss on our indexed debt securities and our AOL Time Warner investment of $67 million (after-tax), or $0.24 loss per basic share and $0.23 loss per diluted share. 2000 net income also includes a $331 million (after-tax) charge, or $1.16 loss per basic share and $1.15 loss per diluted share, to reflect the reclassification of our Latin America business segment from discontinued operations to continuing operations as described above. The extraordinary item in 2000 is a gain of $7 million, or $0.03 earnings per basic and diluted share, related to the early extinguishment of $272 million of long-term debt. For additional information on the indexed debt securities and AOL Time Warner investment, please read Note 8 to our consolidated financial statements. For additional information on our Latin America operations, please read Note 19 to our consolidated financial statements.

(5) 2001 net income includes the following: (i) the cumulative effect of an accounting change resulting from the adoption of SFAS No. 133 ($61 million after-tax gain, or $0.21 earnings per basic and diluted share), (ii) a gain related to the revaluation of our European Energy business segment's share of NEA B.V. (formerly known as N.V. SEP), which was the coordinating body for the Dutch electric generation sector prior to the start of wholesale competition, ($51 million after-tax, or $0.17 earnings per basic and diluted share), (iii) a gain related to the settlement of the stranded cost indemnity obligations of former REPGB shareholders ($37 million after-tax, or $0.13 earnings per basic and diluted share), (iv) a non-cash charge related to the redesign of our employee benefit plans in anticipation of the separation of our regulated and unregulated businesses ($65 million after-tax, or $0.23 loss per basic share and $0.22 loss per diluted share), (v) a charge related to the disposition of our Communications business ($42 million after-tax, or $0.14 loss per basic and diluted share) and (vi) an impairment of our Latin America operations ($51 million after-tax, or $0.17 loss per basic and diluted share). These amounts do not reflect the effect of the third-party minority ownership interest in Reliant Resources. For additional information related to the above items, please read Notes 3(b), 5, 12, 19, and 20 to our consolidated financial statements.

(6) Net income attributable to common stockholders for 1999 and 2000 includes minority interest income of $0.6 million and $1 million, respectively. Net income attributable to common stockholders for 2001 includes minority interest expense of $81 million.

(7) As described in Note 1 to our consolidated financial statements, our consolidated financial statements for 1999, 2000 and 2001 have been restated from amounts previously reported. The restatement had no impact on previously reported consolidated cash flows, operating income or net income.

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

Restatement

On May 9, 2002, Reliant Resources determined that it had engaged in same-day commodity trading transactions involving purchases and sales with the same counterparty for the same volume at substantially the same price, which the personnel who effected these transactions apparently did so with the sole objective of increasing volumes. Reliant Resources commenced a review to quantify the amount and assess the impact of these trades (round trip trades). The Audit Committees of each of the Board of Directors of Reliant Energy and Reliant Resources also directed an internal investigation by outside legal counsel, with assistance by outside accountants, of the facts and circumstances relating to the round trip trades and related matters.

We currently report all trading, marketing and risk management services transactions on a gross basis with such transactions being reported in revenues and expenses except primarily for financial gas transactions

such as swaps. Therefore, the round trip trades were reflected in both our revenues and expenses. The round trip trades should not have been recognized in revenues or expenses (i.e. they should have been reflected on a net basis). However, since the round trip trades were done at the same volume and substantially the same price, they had no impact on our reported cash flows, operating income or net income. In addition to the round trip trades reported on May 13, 2002, Reliant Resources also identified an additional transaction in 1999, which based on available information, Reliant Resources believes was also recorded with the sole objective of increasing volumes but also resulted in increased revenues and fuel and cost of gas sold expense.

In addition, during the May 2001 through September 2001 time frame, Reliant Resources entered into four structured transactions involving a series of forward or swap contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002 or 2003 (four structured transactions). The four structured transactions were intended to increase future cash flow and earnings and to increase certainty associated with future cash flow and earnings, albeit at the expense of 2001 cash flow and earnings. Each series of contracts in a structure were executed contemporaneously with the same counterparty and were for the same commodities, quantities and locations. The contracts in each structure were offsetting in terms of physical attributes. The transactions that settled in 2001 were previously recorded on a gross basis with such transactions being reported in revenues and expenses which resulted in $1.5 billion of revenues, $364 million in fuel and cost of gas sold and $1.2 billion of purchased power expense being recognized during the period from May 2001 through December 31, 2001. Having further reviewed the transactions, Reliant Resources now believes these transactions should have been accounted for on a net basis.

In the course of Reliant Resources' review, Reliant Resources also identified and determined to record on a net basis several transactions for energy related services (not involving round trip trades) that totaled $85 million over the three year period ended December 31, 2001. These transactions were originally recorded on a gross basis.

During the fourth quarter of 2000, two power generation swap contracts with a fair value of $261 million were terminated and replaced with a substantially similar contract providing for physical delivery and designated to hedge electric generation. The termination of the original contracts and execution of the replacement contract represented a substantive modification to the original contract. As a result, upon termination of the original contracts, a contractual liability representing the fair value of the original contracts and a deferred asset of equal amount should have been recorded. As of January 1, 2001, in connection with the adoption of Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133), the deferred asset should have been recorded as a transition adjustment to other comprehensive loss. The liability and transition adjustment should have been amortized on a straight-line basis over the term of the power generation contract replacing the terminated power generation contracts (through May 2004). We previously did not give accounting recognition to these transactions. As a result, we have restated our Consolidated Balance Sheets as of December 31, 2000 and 2001 and the Statements of Consolidated Stockholders' Equity and Comprehensive Income for the year ended December 31, 2001, to appropriately account for these transactions as described above. The restatement had no impact on our reported consolidated cash flows, operating income or net income.

The consolidated financial statements for 1999, 2000 and 2001 have been restated from amounts previously reported. The restatement had no impact on previously reported consolidated cash flows, operating income or net income. A summary of the principal effects of the restatement on our consolidated financial statements for 1999, 2000 and 2001 are set forth in Note 1 to our consolidated financial statements.

The following discussion and analysis has been modified for the restatement and should be read in combination with our consolidated financial statements included in Item 8 of this Form 10-K.

We are a diversified international energy services and energy delivery company that provides energy and energy services primarily in North America and Western Europe. We operate one of the United States' largest electric utilities in terms of kilowatt-hour (KWh) sales, and our three natural gas distribution divisions together form one of the United States' largest natural gas distribution operations in terms of customers served. We invest in the acquisition, development and operation of domestic non-rate regulated power

generation facilities. We own two interstate natural gas pipelines that provide gas transportation, supply, gathering and storage services, and we also engage in wholesale energy marketing and trading.

In this section we discuss our results of operations on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. Our financial reporting business segments include Electric Operations, Natural Gas Distribution, Pipelines and Gathering, Wholesale Energy, European Energy, Retail Energy, Latin America and Other Operations. Historically, Retail Energy has been reported in the Other Operations business segment. For business segment reporting information, please read Notes 1 and 18 to our consolidated financial statements. For additional information regarding these business segments, please read "Business" in Item 1 of this Form 10-K.

We are in the process of separating our regulated and unregulated businesses into two publicly traded companies. In December 2000, we transferred a significant portion of our unregulated businesses to Reliant Resources, which, at the time, was a wholly owned subsidiary. Reliant Resources conducted an initial public offering (Offering) of approximately 20% of its common stock in May 2001. In December 2001, our shareholders approved an agreement and plan of merger by which, subject to regulatory approvals, the following will occur (which we refer to herein as the Restructuring):

- CenterPoint Energy will become the holding company for the Reliant Energy group of companies;
- Reliant Energy and its subsidiaries will become subsidiaries of CenterPoint Energy; and
- each share of Reliant Energy common stock will be converted into one share of CenterPoint Energy common stock.

After the Restructuring, we plan, subject to further corporate approvals, market and other conditions, to complete the separation of our regulated and unregulated businesses by distributing the shares of common stock of Reliant Resources that we own to our shareholders (which we refer to herein as the Distribution). Our goal is to complete the Restructuring and subsequent Distribution as quickly as possible after all the necessary conditions are fulfilled, including receipt of an order from the Securities and Exchange Commission (SEC) granting the required approvals under the Public Utility Holding Company Act of 1935 (1935 Act) and an extension from the IRS for a private letter ruling we have obtained regarding the tax-free treatment of the Distribution. Although receipt or timing of regulatory approvals cannot be assured, we believe we meet the standards for such approvals. We currently expect to complete the Restructuring and Distribution in the summer of 2002.

Effective December 1, 2000, our board of directors approved a plan to dispose of our Latin America business segment through sales of its assets. Accordingly, in our 2000 consolidated financial statements, we reported the results of our Latin America business segment as discontinued operations in accordance with Accounting Principles Board (APB) Opinion No. 30 "Reporting the Results of Operations — Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," (APB Opinion No. 30) for each of the three years in the period ended December 31, 2000. On December 20, 2001, negotiations for the sale of the remaining Latin America investments were terminated as a result of the recent adverse economic developments in Argentina. We will continue to evaluate options related to the future disposition of these assets.

Accordingly, the Latin America business segment is no longer reported as discontinued operations. The related operating results and loss on disposal have been reclassified within the Consolidated Statements of Income for all periods into operating income with respect to consolidated subsidiaries and other income with respect to equity investments in unconsolidated subsidiaries as required for assets held for sale by Emerging Issues Task Force Issue No. 90-6. (EITF 90-6). For additional information regarding the disposal of the Latin America business segment, see Note 19 to our consolidated financial statements.

During 2001, we incurred a pre-tax non-cash charge of $101 million relating to the redesign of some of our benefit plans in anticipation of separation of our regulated and our unregulated businesses. This included a curtailment gain of $23 million related to our pension plans, an $84 million loss related to pension benefit enhancements and a $40 million curtailment loss associated with postretirement benefits.

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

Consolidated Results of Operations

	Year Ended December 31,		
	1999	2000	2001
Revenues	$ 13,794	$ 28,269	$ 40,810
Operating Expenses	(12,535)	(26,432)	(38,817)
Operating Income	1,259	1,837	1,993
(Loss) Income from Equity Investments in Unconsolidated Subsidiaries	(1)	43	57
Gain (Loss) on AOL Time Warner Investment	2,452	(205)	(70)
(Loss) Gain on Indexed Debt Securities	(630)	102	58
Operating Results from Equity Investment in Unconsolidated Latin America Assets	(26)	(41)	—
Impairment of Latin America Unconsolidated Equity Investments	—	(131)	(4)
Loss on Disposal of Latin America Assets	—	(176)	—
Interest Expense and other charges	(551)	(768)	(658)
Minority Interest	1	1	(81)
Other Income, net	60	96	124
Income Before Income Taxes, Extraordinary Items and Cumulative Effect of Accounting Change	2,564	758	1,419
Income Tax Expense	(899)	(318)	(500)
Income Before Extraordinary Items and Cumulative Effect of Accounting Change	1,665	440	919
Extraordinary (Loss) Gain, net of tax	(183)	7	—
Cumulative Effect of Accounting Change, net of tax	—	—	61
Net Income Attributable to Common Stockholders	$ 1,482	$ 447	$ 980
Basic Earnings Per Share	$ 5.20	$ 1.57	$ 3.38
Diluted Earnings Per Share	$ 5.18	$ 1.56	$ 3.35

2001 Compared to 2000

Net Income. We reported consolidated net income of $980 million ($3.35 per diluted share) for 2001 compared to $447 million ($1.56 per diluted share) for 2000. The 2001 results included a cumulative effect of accounting change of $61 million, net of tax, related to the adoption of SFAS No. 133. For additional discussion of the adoption of SFAS No. 133, please read Note 5 to our consolidated financial statements. The 2000 results included an extraordinary gain of $7 million, net of tax, related to the early extinguishment of $272 million of long-term debt. For additional discussion of the extraordinary gain, please read Note 10(b) to our consolidated financial statements.

Our consolidated net income, before cumulative effect of accounting change, was $919 million for 2001 compared to consolidated net income, before extraordinary gain, of $440 million in 2000. The increase of $479 million was primarily due to the following:

- a $674 million increase in gross margins (revenues less fuel and cost of gas sold and purchased power) from our Wholesale Energy business segment, excluding the impact of a $68 million provision related to energy sales to Enron Corp. and its affiliates (Enron) which filed a voluntary petition for bankruptcy during the fourth quarter of 2001;
- a $280 million after-tax decrease in net losses from our Latin America business segment. An additional after-tax impairment of $51 million was recorded in 2001. This business segment had been presented as discontinued operations in 2000;
- a $57 million decrease in operating losses from our Retail Energy business segment;

- a $37 million net gain resulting from the settlement of an indemnity agreement related to certain energy obligations entered into in connection with our acquisition of Reliant Energy Power Generation Benelux N.V. (REPGB), formerly N.V. UNA;

- a $51 million gain recorded in equity income in 2001 related to a preacquisition contingency for the value of NEA B.V. (NEA), the coordinating body for the Dutch electricity generating sector, which is an equity investment in which REPGB holds a 22.5% economic interest;

- a $112 million decrease in net interest expense; and

- a $27 million pre-tax impairment loss on marketable equity securities classified as "available-for-sale" in 2000.

The above items were partially offset by:

- a decrease in operating income of $139 million from our Electric Operations business segment primarily due to the impact of milder weather, reduced rates charged to certain governmental agencies as mandated by the Texas Electric Choice Plan (Texas Electric Restructuring Law), fees paid for the early termination of an accounts receivable factoring agreement and higher benefit expenses;

- a $66 million decrease in our European Energy business segment's gross margins primarily attributable to the Dutch wholesale electric market opening to competition on January 1, 2001, excluding the impact of a $17 million provision related to energy sales to Enron recorded in the fourth quarter of 2001;

- a $101 million pre-tax, non-cash charge relating to the redesign of certain of our benefit plans in anticipation of our separation from Reliant Resources;

- an $85 million pre-tax provision related to energy sales to Enron which was recorded in the fourth quarter of 2001;

- $54 million in pre-tax disposal charges and impairments of goodwill and fixed assets related to the exiting of our Communications business;

- a $37 million decrease in our Wholesale Energy business segment's equity earnings of unconsolidated subsidiaries in 2001 as compared to 2000; and

- an $18 million pre-tax gain in 2000 on the sale of our interest in one of our development-stage electric generation projects.

Net income in 2000 and 2001, excluding the $101 million pre-tax non-cash charge mentioned above, included pension income of $37 million and $5 million, respectively. Pension income declined primarily to a decline in the market value of pension plan assets during 2000. The market value of our pension plan assets continued to decrease during 2001 due primarily to the declines in the U.S. equity markets. As a result of this decline, along with a reduction in the expected return on plan assets and discount rate assumptions, we expect to record pension expense of approximately $40 million in 2002.

During 2001, we contributed to our pension plans approximately 4.5 million shares of Reliant Energy common stock with a fair value of $107 million. As of December 31, 2001, the fair value of Reliant Energy common stock held by these plans was $120 million or 8.7% of the pension plan assets. We do not anticipate a required pension contribution during 2002. Future effects of our pension plans, including effects such as those mentioned above, on our operating results depend on economic conditions, employee demographics, mortality rates and investment performance. For additional information regarding the pension plan assets and the components of pension income, please read Note 12 to our consolidated financial statements.

Operating Income. For an explanation of changes in our operating income for 2001 as compared to 2000, please read the discussion below of operating income (loss) by business segment.

Other Income/Expense. We incurred other expense of $575 million for 2001 compared to other expense of $1.1 billion for 2000. The decrease of $504 million in 2001 as compared to 2000 resulted primarily from the following:

- a $23 million increase in interest income in 2001 earned on under-recovery of fuel costs of our Electric Operations business segment;
- a $51 million gain recorded in equity income with respect to our equity investment in NEA;
- a $112 million decrease in net interest expense, primarily as a result of lower levels of borrowings and lower interest rates in 2001 compared to 2000;
- a $343 million pre-tax decrease in other expense related to reduced losses of our Latin America operations;
- a $103 million pre-tax ($67 million after-tax) non-cash accounting loss on our indexed debt securities and our related AOL Time Warner investment in 2000, and
- a $27 million pre-tax impairment loss on marketable equity securities classified as "available-for-sale" in 2000.

The decrease in other expense noted above was partially offset by:

- minority interest expense of $81 million in 2001 primarily related to minority interest in Reliant Resources as a result of the initial public offering of Reliant Resources' common stock in May 2001 discussed above;
- an $18 million pre-tax gain in 2000 on the sale of our interest in one of our development stage electric generation projects; and
- a $37 million decrease in our Wholesale Energy business segment's equity earnings in unconsolidated subsidiaries in 2001 as compared to 2000. The equity income in both years primarily resulted from an investment in an electric generation plant in Boulder City, Nevada. The plant became operational in May 2000. The equity income related to our investment in the plant declined in 2001 from 2000 primarily due to higher plant outages in 2001 and reduced power prices realized by the project company.

During 2000, we incurred a pre-tax impairment loss of $27 million on marketable equity securities classified as "available-for-sale". Management's determination to recognize this impairment resulted from a combination of events occurring in 2000 related to this investment. Such events affecting the investment included changes occurring in the investment's senior management, announcement of significant restructuring charges and related downsizing for the entity, reduced earnings estimates for this entity by brokerage analysts and the bankruptcy of a competitor of the investment in the first quarter of 2000. These events, coupled with the stock market value of our investment in these securities continuing to be below our cost basis, caused management to believe the decline in fair value to be other than temporary. During 2001, we recognized a pre-tax gain of $14 million from the sale of a portion of this investment. For additional discussion of this investment, please read Note 2(l) to our consolidated financial statements.

Upon adoption of SFAS No. 133 effective January 1, 2001, we recorded a transition adjustment pre-tax gain of $90 million ($58 million net of tax) related to our investment in AOL Time Warner, Inc. (AOL TW) common stock (AOL TW Common) and our related indexed debt obligation. The transition adjustment gain was reported in the first quarter of 2001 as the effect of a change in accounting principle. During 2001, we recorded a $70 million loss on our investment in AOL TW Common. During 2001, we recorded a $58 million gain associated with the fair value of the derivative component of the indexed debt obligation. A detailed discussion follows in the narrative and table presented below.

In 1997, in order to monetize a portion of the cash value of our investment in Time Warner Inc. (TW) convertible preferred stock (TW Preferred), we issued unsecured 7% Automatic Common Exchange Securities (ACES) having an original principal amount of $1.052 billion and maturing July 1, 2000. The

market value of ACES was indexed to the market value of TW common stock (TW Common). On July 6, 1999, we converted our investment in TW Preferred into 45.8 million shares of TW Common. Prior to the conversion, our investment in the TW Preferred was accounted for under the cost method at a value of $990 million. Effective on the conversion date, the shares of TW Common were classified as trading securities under SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and an unrealized gain was recorded in the amount of $2.4 billion ($1.5 billion after-tax) to reflect the cumulative appreciation in the fair value of our investment in Time Warner securities. On the July 1, 2000 maturity date, we tendered 37.9 million shares of TW Common to fully settle our obligations in connection with our ACES obligation. On September 21, 1999, we issued approximately 17.2 million of 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS) having an original principal amount of $1.0 billion. At maturity the holders of the ZENS will receive in cash the higher of the original principal amount of the ZENS (subject to adjustment) or an amount based on the then-current market value of AOL TW Common, or other securities distributed with respect to AOL TW Common. We used $537 million of the net proceeds from the offering of the ZENS to purchase 9.2 million additional shares of TW Common, which are classified as trading securities under SFAS No. 115. Prior to the purchase of additional shares of TW Common on September 21, 1999, we owned approximately 8 million shares of TW Common that were in excess of the 37.9 million shares needed to economically hedge our ACES obligation. Prior to January 1, 2001, an increase above $58.25 (subject to some adjustments) in the market value per share of TW Common resulted in an increase in our liability for the ZENS. However, as the market value per share of TW Common declined below $58.25 (subject to some adjustments), the liability for the ZENS did not decline below the original principal amount. The market value per share of TW Common was $52.24 as of December 31, 2000 and the market value per share of AOL TW Common was $32.10 as of December 31, 2001.

Upon adoption of SFAS No. 133 effective January 1, 2001, the ZENS obligation was bifurcated into a debt component and a derivative component (the holder's option to receive the appreciated value of AOL TW Common at maturity). The derivative component was valued at fair value and determined the initial carrying value assigned to the debt component ($121 million) as the difference between the original principal amount of the ZENS ($1.0 billion) and the fair value of the derivative component at issuance ($879 million). Effective January 1, 2001 the debt component was recorded at its accreted amount of $122 million and the derivative component was recorded at its current fair value of $788 million, as a current liability, resulting in a transition adjustment pre-tax gain of $90 million ($58 million net of tax). The transition adjustment gain was reported in the first quarter of 2001 as the effect of a change in accounting principle. Subsequently, the debt component will accrete through interest charges at 17.5% up to the minimum amount payable upon maturity of the ZENS in 2029, approximately $1.1 billion, and changes in the fair value of the derivative component will be recorded in the Statements of Consolidated Income. During 2001, we recorded a $70 million loss on our investment in AOL TW Common. During 2001, we recorded a $58 million gain associated with the fair value of the derivative component of the ZENS obligation. Changes in the fair value of the AOL TW Common we hold are expected to substantially offset changes in the fair value of the derivative component of the ZENS.

The following table sets forth summarized financial information regarding our investment in AOL TW securities and the ACES and ZENS obligations (in millions).

	AOL TW Investment	ACES	Debt Component of ZENS	Derivative Component of ZENS
Balance at December 31, 1998	$ 990	$ 2,350	$ —	$ —
Issuance of indexed debt securities	—	—	1,000	—
Purchase of TW Common	537	—	—	—
Loss on indexed debt securities	—	388	241	—
Gain on TW Common	2,452	—	—	—
Balance at December 31, 1999	3,979	2,738	1,241	—
Loss (gain) on indexed debt securities	—	139	(241)	—
Loss on TW Common	(205)	—	—	—
Settlement of ACES	(2,877)	(2,877)	—	—
Balance at December 31, 2000	897	—	1,000	—
Transition adjustment from adoption of SFAS No. 133	—	—	(90)	—
Bifurcation of ZENS obligation	—	—	(788)	788
Accretion of debt component of ZENS	—	—	1	—
Gain on indexed debt securities	—	—	—	(58)
Loss on AOL TW Common	(70)	—	—	—
Balance at December 31, 2001	$ 827	$ —	$ 123	$730

For additional information regarding our investment in AOL TW, our indexed debt securities and the effect of adoption of SFAS No. 133 on January 1, 2001 on our ZENS obligation, please read Note 8 to our consolidated financial statements.

Income Tax Expense. The effective tax rate for 2000 and 2001 was 42.0% and 35.2%, respectively. The decrease in the effective tax rate in 2001 compared to 2000 was primarily due to non-recurring increased tax expense arising from the sales of our Latin American investments in 2000, increased earnings of REPGB and decreased state income taxes in 2001, partially offset by the write-off of goodwill in 2001 associated with our Communications business. In 2001 and prior years, the earnings of REPGB were subject to a zero percent Dutch corporate income tax rate as a result of the Dutch tax holiday in effect for the Dutch electricity industry. After December 31, 2001, all of our European Energy business segment's earnings in the Netherlands will be subject to the standard Dutch corporate income tax rate, which is currently 34.5%.

As discussed in Note 14(h) to our consolidated financial statements, the Dutch parliament has adopted legislation allocating to the Dutch generation sector, including REPGB, financial responsibility for certain stranded costs and other liabilities incurred by NEA prior to the deregulation of the Dutch wholesale market. These obligations include NEA's obligations under an out-of-market gas supply contract and three out-of-market electricity contracts. REPGB's allocated share of these liabilities is 22.5%. As a result, we recorded a net stranded cost liability of $369 million and a related deferred tax asset of $127 million at December 31, 2001 for our statutorily allocated share of these gas supply and electricity contracts. We believe that the costs incurred by REPGB subsequent to the tax holiday ending in 2001 related to these contracts will be deductible for Dutch tax purposes. However, due to uncertainties related to the deductibility of these costs, we have recorded an offsetting liability in other liabilities in our consolidated financial statements of $127 million as of December 31, 2001.

2000 Compared to 1999

Net Income. We reported consolidated net income, before the extraordinary gain of $7 million, of $440 million for 2000 compared to $1.7 billion, before an extraordinary loss of $183 million, in 1999. The extraordinary gain in 2000 related to the retirement of certain debt obligations of our REPGB subsidiary. The extraordinary loss in 1999 related to an accounting impairment of certain generation related regulatory assets of our Electric Operations business segment. The 2000 results included the following unusual items:

- an aggregate after-tax, non-cash accounting loss of $67 million on our indexed debt securities and our related AOL TW investment;
- an after-tax loss of $172 million from operations of our Latin America business segment; and
- an after-tax loss of $159 million on the anticipated disposal of our Latin America business segment.

The 1999 results included the following unusual items:

- an aggregate after-tax, non-cash accounting gain of $1.2 billion on our indexed debt securities and our AOL TW investment as discussed above; and
- an after-tax loss of $9 million from operations of our Latin America business segment.

In 1999, the Texas legislature adopted the Texas Electric Restructuring Law. In connection with the implementation of the Texas Electric Restructuring Law, we evaluated the recovery of our generation related regulatory assets and liabilities. We determined that a pre-tax accounting loss of $282 million existed because we believed only the economic value of our generation related regulatory assets (as defined by the Texas Electric Restructuring Law) would be recovered. Therefore, we recorded a $183 million after-tax extraordinary loss in the fourth quarter of 1999. For information regarding the $183 million extraordinary loss, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Electric Operations — Generation" and Note 4(a) to our consolidated financial statements.

In the fourth quarter of 2000, the Latin America business segment sold its investments in El Salvador, Colombia and Brazil for an aggregate $790 million in after-tax proceeds. We recorded a $242 million after-tax loss in connection with the sale of these investments.

In the fourth quarter of 2000, we recorded an additional pre-tax impairment related to our remaining Latin America investments in Argentina of $172 million, based on the expected net realizable value of the businesses upon their disposition.

Operating Income. For an explanation of changes in our operating income for 2000 as compared to 1999, please read the discussion below of operating income (loss) by business segment.

Other Income/Expense. We incurred net other expense of $1.1 billion for 2000 compared to net other income of $1.3 billion for 1999. The decrease in other income/expense of $2.4 billion in 2000 as compared to 1999 resulted primarily from the following:

- a net aggregate pre-tax, non-cash accounting gain in 1999 of $1.8 billion on our indexed debt securities and our AOL TW investment;
- a $322 million pre-tax increase in other expense in 2000 related to losses of our Latin America operations;
- a $214 million increase in net interest expense in 2000 compared to 1999 primarily due to increased levels of short-term borrowings. These increases were associated in part with borrowings to fund the purchase obligation for the acquisition of REPGB in the fourth quarter of 1999 and the first quarter of 2000, the acquisition of the REMA entities in the second quarter of 2000, other acquisitions, capital expenditures and increased margin deposits on energy trading activities; and
- an impairment loss of $27 million on marketable equity securities classified as "available-for-sale" in 2000, distributions of $9 million from venture capital investments in marketable securities classified as "trading" in 1999 and a decline of $19 million in dividend income from our AOL TW investment.

These increases in net other expense were partially offset by the following:

- an increase in interest income of $57 million primarily related to income tax refunds received in 2000 and margin deposits on energy trading activities;
- a pre-tax gain of $18 million in 2000 on the sale of our interest in one of our development stage electric generation projects; and
- a $44 million increase in our Wholesale Energy business segment's equity earnings in unconsolidated subsidiaries in 2000 as compared to 1999.

Income Tax Expense. The effective tax rate for 1999 and 2000 was 35.1% and 42.0%, respectively. The increase in the effective tax rate in 2000 compared to 1999 was primarily due to book/tax basis differences realized on the sale of our Latin American investments, including the write-off of deferred tax assets related to the Latin America business segment, partially offset by the increased earnings of REPGB. Under Dutch corporate income tax laws, the earnings of REPGB were subject to a zero percent Dutch corporate income tax rate as a result of the Dutch tax holiday in effect for the Dutch electricity industry.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (loss) for each of our business segments for 1999, 2000 and 2001 (in millions). Some amounts from the previous years have been reclassified to conform to the 2001 presentation of the financial statements. These reclassifications do not affect consolidated earnings.

Operating Income (Loss) by Business Segment

	Year Ended December 31,		
	1999	2000	2001
		(In millions)	
Electric Operations	$ 981	$1,230	$1,091
Natural Gas Distribution	158	118	130
Pipelines and Gathering	131	137	137
Wholesale Energy	27	479	899
European Energy	32	89	56
Retail Energy	(14)	(70)	(13)
Latin America	(4)	(44)	(75)
Other Operations	(52)	(102)	(232)
Total Consolidated Operating Income	$1,259	$1,837	$1,993

Electric Operations

For a discussion of the factors that may affect the future results of operations of our Electric Operations business segment, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Electric Operations."

The following table provides summary data regarding the results of operations of our Electric Operations business segment for 1999, 2000 and 2001 (in millions, except electric sales data):

	Year Ended December 31,		
	1999	2000	2001
Operating Revenues:			
Base revenues(1)	$ 2,968	$ 3,141	$ 3,022
Reconcilable fuel revenues(2)	1,515	2,353	2,483
Total operating revenues	4,483	5,494	5,505
Operating Expenses:			
Fuel and purchased power	1,559	2,412	2,538
Operation and maintenance	926	963	1,047
Depreciation and amortization	667	507	453
Other operating expenses	350	382	376
Total operating expenses	3,502	4,264	4,414
Operating Income	$ 981	$ 1,230	$ 1,091
Electric Sales (gigawatt-hours (GWh)):			
Residential	21,144	22,727	21,371
Commercial	16,616	17,594	17,967
Industrial — Firm	26,020	27,707	26,761
Industrial — Interruptible	5,460	5,542	4,298
Other	2,867	1,724	928
Total	72,107	75,294	71,325

(1) Includes miscellaneous revenues, non-reconcilable fuel revenues and purchased power-related revenues.

(2) Includes revenues collected through a fixed fuel factor and surcharges net of adjustments for over/under recovery of fuel.

2001 Compared to 2000. Our Electric Operations business segment's operating income for 2001 decreased $139 million compared to 2000. The decrease was primarily due to milder weather, decreased customer demand, increased contract services and benefit expenses and a charge recorded in the fourth quarter of 2001 resulting from the early termination of an accounts receivable factoring agreement. The decrease was also due to the implementation of the pilot program for Texas deregulation in August 2001, reduced rates for certain governmental agencies and increased administrative expenses related to the separation of our regulated and unregulated businesses. These decreases were partially offset by decreased amortization expense and customer growth.

Base revenues decreased $119 million in 2001 due to decreased customer demand as a result of the effect of milder weather compared to 2000 and decreased customer usage on a weather normalized basis. The weather impact represented approximately $84 million of the decrease in base revenues in 2001 as compared to 2000.

The 6% increase in reconcilable fuel revenue in 2001 resulted primarily from increased fuel costs as discussed below. The Texas Utility Commission provides for recovery of certain fuel and purchased power costs through a fixed fuel factor included in electric rates. Revenues collected through this factor are adjusted monthly to equal expenses; therefore, these revenues and expenses have no effect on earnings unless fuel costs are subsequently determined not to be recoverable. The adjusted over/under recovery of fuel costs is recorded in our Consolidated Balance Sheets as regulatory liabilities or regulatory assets, respectively. For information regarding the effect of the Texas Electric Restructuring Law on fuel recovery beginning in 2002, please read

"Business — Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" in Item 1 of this Form 10-K and Note 4(c) to our consolidated financial statements for information regarding Reliant Energy HL&P fuel filings.

Fuel and purchased power expenses in 2001 increased by $126 million, or 5%, over 2000 expenses. This increase is due to increased purchased power volume related to the load balancing requirements associated with the Electric Reliability Council of Texas, Inc. (ERCOT) adapting to a single control area, with a slightly higher cost for purchased power ($44.26 and $44.42 per MWh in 2000 and 2001, respectively). The purchased power increase was partially offset by the decline in the volume of natural gas used at a slightly higher rate ($3.98 and $4.23 per MMBtu in 2000 and 2001, respectively).

Operation, maintenance and other operating expenses increased $78 million in 2001 compared to 2000 primarily due to the following items:

- a $32 million increase in benefits expense primarily driven by medical and pension costs;
- a $16 million increase in contract services due to additional major and solid fuel outages at our generating plants in 2001 compared to shorter, routine outages in 2000;
- an $11 million increase in administrative expenses related to the separation of our regulated and unregulated businesses; and
- a $20 million charge recorded in the fourth quarter of 2001 resulting from the early termination of an accounts receivable factoring agreement.

Depreciation and amortization expense decreased $54 million primarily due to a decrease in amortization of the book impairment regulatory asset recorded in June 1999 and decreased amortization expense due to regulatory assets related to cancelled projects being fully amortized in June 2000, partially offset by accelerated amortization of certain regulatory assets related to energy conservation management as required by the Texas Utility Commission. In June 1998, the Texas Utility Commission issued an order approving a transition to competition plan (Transition Plan) filed by Reliant Energy HL&P in December 1997. In order to reduce Reliant Energy HL&P's exposure to potential stranded costs related to generation assets, the Transition Plan permitted the redirection of depreciation expense to generation assets that Reliant Energy HL&P otherwise would apply to transmission, distribution and general plant assets. In addition, the Transition Plan provided that all earnings above a stated overall annual rate of return on invested capital be used to recover Reliant Energy HL&P's investment in generation assets. Reliant Energy HL&P implemented the Transition Plan effective January 1, 1998. For information regarding items that affect depreciation and amortization expense of our Electric Operations business segment pursuant to the Texas Electric Restructuring Law and the Transition Plan, see Notes 2(g) and 4(a) to our consolidated financial statements, which are incorporated herein by reference.

2000 Compared to 1999. Our Electric Operations business segment's operating income for 2000 increased $249 million compared to 1999. The increase was primarily due to decreased depreciation and amortization expense, strong customer growth and warmer weather, partially offset by increased operation and maintenance expenses and other taxes.

Base revenues increased $173 million in 2000 due to continued customer growth and increased demand from the effects of weather as compared to 1999. Growth in usage per customer and number of customers contributed $132 million of the increase in base revenues in 2000.

Fuel and purchased power expenses in 2000 increased by $853 million, or 55%, over 1999 expenses. The increase is primarily the result of higher reconcilable costs for natural gas ($2.47 and $3.98 per MMBtu in 1999 and 2000, respectively), higher costs for purchased power ($26.46 and $44.26 per MWh in 1999 and 2000, respectively) and higher sales due to customer growth and increased demand, which led to increased production.

Operation, maintenance and other operating expenses increased $69 million in 2000 compared to 1999 primarily due to the following items:

- a $25 million increase due to transmission expenses resulting from the wholesale rates established by the Texas Utility Commission;
- a $22 million increase in state franchise taxes and municipal franchise fees due to increased earnings and cash receipts;
- a $24 million assessment for the 1999 and 2000 System Benefit Fund, which was established by the Texas Electric Restructuring Law to insure that public schools were not impacted by the loss of taxes related to the lower property values of generation assets, substantially offset by a decrease in property taxes of $21 million; and
- a $22 million increase in other operation and maintenance expense.

Depreciation and amortization expense decreased $160 million primarily due to our discontinuance of recording additional depreciation and redirected depreciation pursuant to the Transition Plan, the extension of electric generation assets' depreciable lives, fully amortizing some investments in lignite reserves associated with a cancelled generation station and ceasing amortization of regulatory assets pursuant to the Texas Electric Restructuring Law.

Natural Gas Distribution

Our Natural Gas Distribution business segment's operations consist of intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas and some non-rate regulated retail marketing of natural gas.

For a discussion of the factors that may affect future results of operations of our Natural Gas Distribution business segment, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of RERC's Operations — Natural Gas Distribution."

The following table provides summary data regarding the results of operations of our Natural Gas Distribution business segment for 1999, 2000 and 2001 (in millions, except throughput data):

	Year Ended December 31,		
	1999	2000	2001
Operating Revenues	$2,788	$4,504	$4,742
Operating Expenses:			
Natural gas	1,936	3,590	3,814
Operation and maintenance	470	553	541
Depreciation and amortization	137	145	147
Other operating expenses	87	98	110
Total operating expenses	2,630	4,386	4,612
Operating Income	$ 158	$ 118	$ 130
Throughput Data (in billion cubic feet (Bcf)):			
Residential and commercial sales	286	320	310
Industrial sales	53	57	50
Transportation	47	50	49
Retail	400	565	445
Total Throughput	786	992	854

2001 Compared to 2000. Our Natural Gas Distribution business segment's operating income increased $12 million in 2001 from 2000. Operating margins (revenues less fuel costs) in 2001 were $14 million higher than in 2000 primarily due to increased volumes in the first quarter of 2001 due to the effect of colder weather.

Operation and maintenance expenses decreased in 2001 as compared to 2000 primarily due to expenses incurred in 2000 in connection with exiting certain non-rate regulated natural gas business activities outside our established market areas offset by the following items:

- increased bad debt expense due to higher natural gas prices in the first quarter of 2001;
- higher employee benefit cost; and
- changes in estimates of unbilled revenues and recoverability of deferred gas accounts and other items.

Generally, our utility operations of the Natural Gas Distribution business segment are allowed to flow through the cost of natural gas to our customers through purchased gas adjustment provisions in rates pursuant to regulations of the states in which they operate. Differences between actual gas costs and the amount collected from customers are deferred on the balance sheet so that there is no impact on operating income.

2000 Compared to 1999. Our Natural Gas Distribution business segment's operating income decreased $40 million in 2000 from 1999. Increases in revenues and natural gas expenses in 2000 compared to 1999 were due primarily to the increase in the price of natural gas. In addition, operating revenues increased $6 million related to gains from the effect of a financial hedge of our Natural Gas Distribution business segment's earnings against unseasonably warm weather during peak heating months. Slightly increased operating margins (revenues less fuel costs) in 2000 were offset by higher operating expenses and higher depreciation expense in 2000.

Operation and maintenance expenses increased in 2000 primarily due to the following items:

- costs incurred in connection with some non-rate regulated retail natural gas business activities outside our established market areas, which we exited in the fourth quarter of 2000;
- additional provisions against receivable balances resulting from the implementation of a new billing system for Arkla; and
- increased employee benefit costs.

Pipelines and Gathering

Our Pipelines and Gathering business segment operates two interstate natural gas pipelines, as well as provides gathering and pipeline services.

For a discussion of the factors that may affect future results of operations of our Pipelines and Gathering business segment, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of RERC's Operations — Pipelines and Gathering."

The following table provides summary data regarding the results of operations of our Pipelines and Gathering business segment for 1999, 2000 and 2001 (in millions, except throughput data):

	Year Ended December 31,		
	1999	2000	2001
Operating Revenues	$ 331	$ 384	$ 415
Operating Expenses:			
Natural gas	41	76	79
Operation and maintenance	91	100	121
Depreciation and amortization	53	56	58
Other operating expenses	15	15	20
Total operating expenses	200	247	278
Operating Income	$ 131	$ 137	$ 137
Throughput Data (Bcf):			
Natural gas sales	15	14	18
Transportation	836	845	819
Gathering	270	288	300
Elimination(1)	(14)	(12)	(3)
Total Throughput	1,107	1,135	1,134

(1) Elimination of volumes both transported and sold.

2001 Compared to 2000. Our Pipelines and Gathering business segment's operating income for 2001 was consistent with 2000 results. Increased gas gathering and processing revenues were offset by increased operating expenses associated with a pipeline rate case which began in 2001, higher employee benefit costs and increased other operating expenses.

2000 Compared to 1999. Our Pipelines and Gathering business segment's operating income for 2000 increased $6 million, primarily due to increased gas gathering and processing revenues. Natural gas expense increased $35 million in 2000, primarily due to the increased cost of natural gas per unit. Operation and maintenance expense increased $9 million in 2000, primarily due to the implementation of various projects throughout the year.

Wholesale Energy

Our Wholesale Energy business segment, which is conducted through Reliant Resources, includes our non-rate regulated power generation operations in the United States and our wholesale energy trading, marketing, origination and risk management operations in North America.

As of December 31, 2001, we owned or leased electric power generation facilities with an aggregate net generating capacity of 11,109 megawatts (MW) in the United States. We acquired our first power generation facility in April 1998, and have increased our aggregate net generating capacity since that time principally through acquisitions, as well as contractual agreements and the development of new generating projects. As of December 31, 2001, we had 3,587 MW of additional net generating capacity under construction, including facilities having 2,120 MW that are being constructed under a construction agency agreement by off-balance sheet special purpose entities. We consider a project to be "under construction" once we have acquired the necessary permits to begin construction, broken ground on the project site and contracted to purchase machinery for the project, including the combustion turbines. On May 12, 2000, one of our subsidiaries purchased entities owning electric power generating assets and development sites located in Pennsylvania, New Jersey and Maryland having an aggregate net generating capacity of approximately 4,262 MW. For additional information regarding this acquisition of our Mid-Atlantic generating assets completed in May 2000

by Wholesale Energy, including the accounting treatment of this acquisition, please read Note 3(a) to our consolidated financial statements.

On February 19, 2002, we acquired all of the outstanding shares of common stock of Orion Power Holdings, Inc. (Orion Power) for $26.80 per share in cash for an aggregate purchase price of $2.9 billion. As of February 19, 2002, Orion Power's debt obligations were $2.4 billion ($2.1 billion net of cash acquired, some of which is restricted pursuant to debt covenants). Orion Power is an independent electric power generating company that was formed in March 1998 to acquire, develop, own and operate power-generating facilities in certain deregulated wholesale markets in North America. As of February 28, 2002, Orion Power had 81 power plants in operation with a total generating capacity of 5,644 MW and an additional 804 MW under construction or in various stages of development.

For a discussion of the factors that may affect the future results of operations of Wholesale Energy, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations."

The following table provides summary data regarding the results of operations of our Wholesale Energy business segment for 1999, 2000 and 2001 (in millions, except operations data).

	Year Ended December 31,		
	1999	2000	2001
Operating Revenues	$6,495	$18,072	$29,742
Operating Expenses:			
Fuel and cost of gas sold	3,599	10,295	14,834
Purchased power	2,688	6,775	13,300
Operation and maintenance	154	402	564
Depreciation and amortization	21	108	118
Other operating expenses	6	13	27
Total Operating Expenses	6,468	17,593	28,843
Operating Income	$ 27	$ 479	$ 899
Operations Data:			
Net Generating Capacity (MW)	4,469	9,231	11,109
Electricity Wholesale Power Sales (MMWh)(1)	82	172	300
Natural Gas Sales (Bcf)(2)	1,564	2,423	3,508

(1) Million megawatt hours.

(2) Billion cubic feet.

2001 Compared to 2000. Wholesale Energy's operating income increased by $420 million in 2001 compared to 2000. The results for 2001 include a $68 million provision against net receivables, trading and marketing assets and non-trading derivative balances related to Enron, and a $29 million provision and a $12 million net write-off against receivable balances related to energy sales in California. A $39 million provision against receivable balances related to energy sales in California was recorded in 2000.

The increase in operating income was primarily due to increased gross margins. Gross margins for Wholesale Energy increased by $606 million primarily due to increased volumes on power sales from our generation facilities, increased volumes from our trading and marketing activities and the addition of our Mid-Atlantic assets and strong commercial and operational performance in other regions. Margins on power sales from our generation facilities, excluding a $63 million provision related to Enron, increased by $429 million in the West region (Arizona, California and portions of New Mexico and Nevada), $85 million in the Mid-Atlantic region, and $32 million in other regions in 2001 compared to 2000. Favorable market conditions in the first six months of 2001 in the West region resulting from a combination of factors, including reduction in

available hydroelectric generation resources, increased demand and decreased electric imports, positively impacted Wholesale Energy's operating margins. These favorable market conditions did not exist in the second half of 2001, and we do not expect them to return in 2002. Trading and marketing gross margins, excluding a $5 million provision related to Enron, increased $113 million from $197 million in 2000 to $310 million in 2001 primarily as a result of increased natural gas trading volumes. These results were partially offset by the $68 million provision related to Enron as discussed above, higher operation and maintenance expenses from facilities in the Mid-Atlantic region acquired in 2000, higher general and administrative expenses and increased depreciation expense.

The following table provides further summary data regarding gross margin by commodity of Wholesale Energy for 2000 and 2001.

	Year Ended December 31,	
	2000	2001
	(In millions)	
Gas revenues	$ 9,326	$13,799
Power revenues	8,666	15,931
Other commodity revenues	80	80
Credit provision related to Enron	—	(68)
Total revenues	18,072	29,742
Cost of gas sold	9,213	13,571
Fuel and purchased power	7,770	14,499
Other commodity costs	87	64
Total cost of sales	17,070	28,134
Gross margin	$ 1,002	$ 1,608

Wholesale Energy's revenues increased by $11.7 billion (65%) in 2001 compared to 2000. The increased revenues were primarily due to increased volumes for natural gas (approximately $4.2 billion) and power sales (approximately $6.6 billion) and to a lesser extent increased prices for power sales compared to 2000, which increased approximately $0.7 billion. Wholesale Energy's fuel and cost of gas sold and purchased power increased by $11.1 billion in 2001 compared to 2000, largely due to increased volumes for natural gas and power sales and to a lesser extent increases in power generation plant output, which increased approximately 33% compared to 2000, and increased prices for power purchases.

Operation and maintenance expenses for Wholesale Energy increased $162 million in 2001 compared to the same period in 2000, primarily due to costs associated with the operation and maintenance of generating plants acquired in the Mid-Atlantic region of $53 million and higher lease expense of $38 million associated with the Mid-Atlantic generation facilities' sale-leaseback transactions that were entered into in August 2000. The higher lease expense associated with the Mid-Atlantic generating facilities was offset by lower interest expense in the consolidated results of operations in 2001 compared to 2000. Other operating expenses increased $14 million in 2001 compared to 2000, primarily due to higher administrative costs to support growing wholesale commercial activities of $69 million and higher legal and regulatory expenses related to the West region of $25 million, partially offset by decreased development expenses of $12 million. Depreciation and amortization expense increased by $10 million in 2001 compared to 2000 primarily as a result of higher expense related to the depreciation of our Mid-Atlantic plants, which were acquired in May 2000, and other generating plants placed into service during 2001, partially offset by a decrease in amortization of our air emissions regulatory allowances of $8 million.

2000 Compared to 1999. Wholesale Energy's operating income increased $452 million for 2000 compared to 1999. The increase was primarily due to increased energy sales volumes, higher prices for energy and ancillary services, and improved operating results from trading and marketing activities, as well as

expansion of our generation operations into regions other than the Western United States, including the Mid-Atlantic United States, Florida and Texas.

Wholesale Energy's operating revenues increased $11.6 billion (178%) for 2000 compared to 1999. The increase was primarily due to an increase in prices and volumes for both gas and power sales in 2000 compared to 1999. Wholesale Energy's fuel and cost of gas sold and purchased power costs increased $6.7 billion and $4.1 billion, respectively, in 2000 compared to 1999. The increase in fuel and cost of gas sold was primarily due to an increase in gas volumes purchased, and to increases in plant output and in the price of gas. The increase in purchased power cost was primarily due to a higher average cost of power and higher power volumes purchased. Operation and maintenance expenses and other operating expenses increased $248 million and $7 million, respectively, in 2000 compared to 1999. These increases were primarily due to costs associated with the maintenance of facilities acquired or placed into commercial operation during the period, lease expense associated with the Mid-Atlantic generating facilities sale-leaseback transactions, higher run rates at existing facilities, increased costs associated with developing new power generation projects and higher staffing levels to support increased sales and expanded trading and marketing efforts. Depreciation and amortization expense for 2000 increased $87 million as compared to 1999, primarily as a result of our acquisition of the Mid-Atlantic generating facilities and other generating facilities in 2000.

European Energy

Our European Energy business segment, which is conducted through Reliant Resources, includes the operations of REPGB and its subsidiaries and our European trading and power origination operations. We created European Energy in the fourth quarter of 1999 with the acquisition of REPGB and the formation of our European trading and power origination operations. European Energy generates and sells power from its generation facilities in the Netherlands and participates in the emerging wholesale energy trading markets in Northwest Europe.

Effective October 7, 1999, we acquired REPGB, a Dutch generation company, for a net purchase price of $1.9 billion. From October 1, 1999, our operating results include the results of operations of REPGB. The impact of REPGB's results of operations from October 1 through October 7, 1999 was immaterial to our consolidated results of operations. For additional information regarding the acquisition of REPGB, please read Note 3(b) to our consolidated financial statements.

In connection with our evaluation of the acquisition of REPGB, we also began to assess and formulate an employee severance plan to be undertaken as soon as reasonably possible post-acquisition. The intent of this plan was to make REPGB competitive in the Dutch electricity market when it became deregulated on January 1, 2001. This plan was finalized, approved and completed in September 2000. At that time, we recorded the severance liability as a purchase price adjustment in the amount of $19 million. During 2001, we utilized $8 million of the reserve. As of December 31, 2001, the remaining severance liability is $11 million.

REPGB and the other major Dutch generators historically operated under a protocol agreement, pursuant to which the generators provided capacity and energy to distributors in exchange for regulated production payments, plus compensation for actual fuel expended in the production of electricity over the period from 1997 through 2000. Effective January 1, 2001, these agreements expired in all material respects. Beginning January 1, 2001, the Dutch wholesale electric market was opened to competition. Consistent with our expectations at the time that we made the acquisition, REPGB experienced a significant decline in electric margins in 2001 attributable to the deregulation of the wholesale electric market.

In 2001, we evaluated strategic alternatives for our European Energy business segment, including a possible sale. We completed our evaluation, and determined that given current market conditions and prices, it is not advisable to sell our European Energy operations. Consequently, we decided to continue to own and operate our European Energy business segment and to expand our trading and origination activities in Northwest Europe. During December 2001, we evaluated our European Energy business segment's long-lived assets and goodwill for impairment. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. As of December 31, 2001, pursuant to SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets

and for Long-Lived Assets to Be Disposed Of," (SFAS No. 121), no impairment has been indicated. For assessing of impairment in 2002, under SFAS No. 142, "Goodwill and Other Intangible Assets," (SFAS No. 142), please read "— New Accounting Pronouncements,".

For additional information regarding these and other factors that may affect the future results of operations of European Energy, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our European Energy Operations."

For information regarding foreign currency matters, please read Note 5(b) to our consolidated financial statements and "— Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of this Form 10-K.

The following table provides summary data for the results of operations of our European Energy business segment for 1999, 2000 and 2001 (in millions, except operations data).

	Three Months Ended December 31, 1999	Year Ended December 31, 2000	Year Ended December 31, 2001
Operating Revenues	$ 153	$ 580	$1,192
Operating Expenses:			
Fuel and purchased power	68	294	989
Operation and maintenance	32	121	71
Depreciation and amortization	21	76	76
Total Operating Expenses	121	491	1,136
Operating Income	$ 32	$ 89	$ 56
Operating Data:			
Net Generation Capacity (MW)	3,476	3,476	3,476
Electric Sales (MMWh)	3	13	42

2001 Compared to 2000. European Energy's operating income decreased by $33 million for 2001 compared to 2000. This decrease was primarily due to the anticipated decline in electric power generation gross margins (revenues less fuel and purchased power), as the Dutch electric market was completely opened to wholesale competition on January 1, 2001. Further contributing to the decline in operating margins were a number of unscheduled outages at our electric generating facilities. We estimate that these unplanned outages resulted in losses of $11 million. Increased margins from ancillary services of $33 million and district heating sales of $9 million in 2001 compared to 2000 and efficiency and energy payments from NEA totaling $30 million in 2001 partially offset this decline. Trading gross margins decreased $12 million from a $3 million gross margin in 2000 to a $9 million gross margin loss in 2001 primarily as a result of a $17 million provision against receivable and trading and marketing asset balances related to Enron. Excluding this provision, trading gross margins increased primarily due to a significant increase in power trading volumes, trading origination transactions and increased volatility in the Dutch and German markets. In addition, the decrease in operating income was partially offset by a $37 million net gain related to the settlement of an indemnity agreement with the former shareholders of REPGB in the fourth quarter of 2001, as discussed below.

European Energy's operating revenues increased by $612 million for 2001 compared to 2000. The increase was primarily due to increased trading revenues in the Dutch, German and Austrian power markets of $544 million and, to a lesser extent, increased volumes of electric generation sales, which increased 41%, partially offset by a 29% decrease in prices for power sales. Fuel and purchased power costs increased $695 million for 2001 compared to 2000 primarily due to increased purchased power for trading activities, and to a lesser extent increased cost of natural gas due to higher gas prices, increased output from our generating facilities and increased transmission and grid charges as a result of a change in the tariff structure.

Operation and maintenance expenses decreased by $50 million for 2001 compared to 2000. These expenses declined primarily due to (a) the net gain of $37 million recorded in operation expenses related to

the settlement of the former shareholders' indemnity obligation, as discussed below, (b) provisions in 2000 against environmental tax subsidies receivable from Dutch distribution companies, REPGB's former shareholders and the Dutch government, coupled with the reversal of such accrual in 2001 due to the indemnity obligation settlement with REPGB's former shareholders and (c) decreases in provisions for environmental liabilities, employee benefits and other accruals totaling $6 million. This decrease was partially offset by an increase in personnel and operating expenses related to our trading operations, facilities costs and systems upgrades.

In December 2001, REPGB and its former shareholders entered into a settlement agreement resolving the former shareholders' stranded cost indemnity obligations under the purchase agreement of REPGB. During the fourth quarter of 2001, we recognized a net settlement gain of $37 million in operation expenses for the difference between the sum of (a) the cash settlement consideration of $202 million, and REPGB's rights to claim future distributions of our NEA investment of an estimated $248 million and (b) the amount recorded as "stranded cost indemnity receivable" related to the stranded cost gas and electric commitments of $369 million and claims receivable related to stranded costs incurred in 2001 of $44 million both previously recorded in our consolidated balance sheet. Future changes in the valuation of the stranded cost import contracts that remain an obligation of REPGB will be recorded as adjustments to our consolidated statement of income, thus introducing potential earnings volatility. For additional information regarding the settlement, please read Note 14(h) to our consolidated financial statements.

2000 Compared to 1999. For the year ended December 31, 2000, European Energy reported operating income of $89 million. European Energy reported operating income of $32 million for the three months ended December 31, 1999.

Retail Energy

Our Retail Energy business segment, which is conducted through Reliant Resources, provides energy products and services to end-use customers, ranging from residential and small commercial customers to large commercial, institutional and industrial customers. In addition, Retail Energy provided billing, customer service and credit and collection services to the Electric Operations business segment and remittance services to the Electric Operations business segment and two of the divisions of the Natural Gas Distribution business segments. The service agreement governing these services terminated on December 31, 2001. Retail Energy charged the regulated electric and natural gas utilities for these services at cost. Reliant Resources acquired approximately 1.7 million electric retail customers in the Houston metropolitan area when the Texas market opened to competition in January 2002. During the first half of 2002, the Texas electric retail market will be largely focused on the extensive efforts necessary to transition customers from the utilities to the affiliated retail electric providers. Reliant Resources expects to expand its marketing efforts for small residential and commercial customers (*i.e.*, customers with an aggregate peak demand at or below one MW) to other areas in Texas outside of the Houston territory during the second quarter of 2002. Reliant Resources signed 246 contracts with large commercial, industrial and institutional (e.g., hospitals, universities, school systems and government agencies) customers (*i.e.*, customers with an aggregate peak demand of more than one MW) during 2001, with an aggregate peak electric energy demand of approximately 3,700 MW and serving approximately 12,000 meter locations. These customers are both in the Houston metropolitan area as well as outside of the Houston territory. Reliant Resources' marketing efforts for large commercial, industrial and institutional customers are continuing throughout the competitive region of the ERCOT.

For a discussion of the factors that may affect the future results of operations of Retail Energy, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations."

The following table provides summary data regarding the results of operations of our Retail Energy business segment for 1999, 2000 and 2001 (in millions).

	Year Ended December 31,		
	1999	2000	2001
Operating Revenues	$ 23	$ 64	$211
Operating Expenses:			
Operation and maintenance	37	130	213
Depreciation and amortization	—	4	11
Total Operating Expenses	37	134	224
Operating Loss	$(14)	$(70)	$(13)

2001 Compared to 2000. Our Retail Energy business segment's operating loss decreased by $57 million for 2001 compared to 2000. The operating loss reduction was primarily due to increased sales of energy and energy services to commercial, industrial and institutional customers, partially offset by (a) increased personnel costs and employee related costs and (b) increased costs associated with developing an infrastructure necessary to prepare for competition in the retail electric market in Texas. Contracted energy sales to large commercial, industrial and institutional customers are accounted for under the mark-to-market method of accounting. These energy contracts are recorded at fair value in revenue upon contract execution. The net changes in their market values are recognized in the income statement in revenue in the period of the change. During 2001, our Retail Energy business segment recognized $74 million of mark-to-market revenues related to commercial, industrial and institutional energy contracts of which $73 million relates to energy that will be supplied in future periods ranging from one to three years.

Operating revenues increased by $147 million for 2001 compared to 2000 largely due to increased revenues from sales of energy and energy services to large commercial, industrial and institutional customers, as well as increased revenues for the services provided to the Electric Operations and Natural Gas Distribution business segments. Operations and maintenance costs increased by $83 million in 2001 as compared to 2000, primarily due to increased personnel and employee-related costs and costs related to building an infrastructure necessary to prepare for competition in the retail electric market in Texas totaling $35 million, increased costs incurred in performing services for the Electric Operations and Natural Gas Distribution business segments of $31 million and increased purchased power expenses of $27 million in 2001 primarily due to a $22 million increase in wholesale electricity purchases and a $5 million increase in the cost of transmission service both related to the Texas retail pilot program during the last half of 2001. Our Wholesale Energy business segment purchases and manages Retail Energy's wholesale purchased power requirements needed to fulfill its retail energy commitments. The Wholesale Energy business segment charges Retail Energy for the purchased power at its actual cost and charges an administrative fee for such service.

2000 Compared to 1999. Retail Energy's operating loss increased $56 million for 2000 compared to 1999. Operating revenues increased $41 million (178%) for 2000 as compared to 1999. This increase was primarily the result of the inclusion of revenues generated by the operations acquired during November 1999, additional revenue generated by an increase in the number of new energy service contracts. For 2000 as compared to 1999, operations and maintenance costs increased $93 million primarily due to costs associated with servicing contracts acquired during 1999 as well as new contracts entered into in 2000 and costs related to building an infrastructure necessary to prepare for competition in the retail electric market in Texas. In addition, during the fourth quarter of 2000, Reliant Resources incurred an obligation to pay $12 million in order to secure the naming rights to a Houston sports complex and for the initial advertising of which $10 million was expensed in 2000. Starting in 2002, when the new stadium in the sports complex is operational, Reliant Resources will pay $10 million each year through 2032 for annual advertising associated with the sports complex.

Latin America

Effective December 1, 2000 (Measurement Date), Reliant Energy's board of directors approved a plan to dispose of our Latin America business segment through sales of its assets. Accordingly, in our 2000 consolidated financial statements, we reported the results of our Latin America business segment as discontinued operations in accordance with APB Opinion No. 30 for each of the three years in the period ended December 31, 2000.

In the fourth quarter of 2000, the Latin America business segment sold its investments in El Salvador, Colombia and Brazil for an aggregate $790 million in after-tax proceeds. We recorded a $242 million after-tax loss in connection with the sale of these investments. Through our subsidiaries, we continue to operate investments in Argentina which include a 100% interest in a 160 MW cogeneration project, Argener, and a 90% interest in a utility, EDESE (collectively, the Argentine Investments).

In the fourth quarter of 2000 and in the first quarter of 2001, we recorded after-tax impairments related to the Argentine Investments of $89 million and $7 million, respectively, based on the expected net realizable value of the businesses upon their disposition.

On December 20, 2001, negotiations for the sale of the Argentine Investments were terminated as a result of recent adverse economic developments in Argentina. We will continue to evaluate options related to the future disposition of these assets.

Accordingly, the Latin America business segment is no longer reported as discontinued operations. The related operating results and loss on disposal have been reclassified within the Statements of Consolidated Income for all periods into operating income with respect to consolidated subsidiaries and other income with respect to equity investments in unconsolidated subsidiaries as required for assets held for sale by EITF 90-6.

During December 2001, we concluded that there was an impairment related to the remaining assets in this business segment. This evaluation resulted in an after-tax impairment charge of $43 million, representing the excess of book value over estimated net realizable value. As of December 31, 2001, we had $8 million of Latin America net assets held for sale recorded in our Consolidated Balance Sheets. The charge was included as a component of operating income with respect to consolidated subsidiaries and other income with respect to equity investments in unconsolidated subsidiaries. The impairment was primarily related to recent adverse economic developments in Argentina. We do not intend to invest additional resources in these operations.

Other Operations

Our Other Operations business segment includes the operations of our Communications and venture capital businesses, non-operating investments, certain real estate holdings and unallocated corporate costs. For additional information about our exiting of the Communications business, please read Note 20 to our consolidated financial statements. After Restructuring and Distribution, our Other Operations business segment will consist primarily of Reliant Energy Thermal Systems, Inc., Reliant Energy Power Systems, Inc., office buildings and other real estate used in our business operations and unallocated corporate costs.

2001 Compared to 2000. Other Operations' operating loss increased by $130 million to $232 million in 2001 compared to $102 million in 2000. During 2001, we incurred a pre-tax non-cash charge of $101 million relating to the redesign of certain of our benefit plans in anticipation of separation of our regulated and unregulated businesses. In connection with our decision to exit the Communications business, we determined that the goodwill associated with the Communications business was impaired. We recorded $54 million of pre-tax disposal charges in 2001, including the impairment of goodwill of $19 million and fixed assets of $22 million, and severance accruals, lease cancellation costs and other incremental costs associated with exiting the Communications business, totaling $13 million. The goodwill and fixed assets impairments are included in depreciation and amortization expense. These items were partially offset by decreased corporate operating expenses of $12 million and decreased charitable contributions to a charitable foundation of $15 million of equity securities classified as "trading." For additional information about the benefit charge noted above, please read Note 12 to our consolidated financial statements.

2000 Compared to 1999. Other Operations had an operating loss of $102 million for 2000 compared to a $52 million operating loss for 1999. This increased loss was primarily due to increased Communications business expenses and a $15 million non-cash charitable contribution of equity securities, as discussed above.

TRADING AND MARKETING OPERATIONS

Through Reliant Resources, we trade and market power, natural gas and other energy-related commodities and provide related risk management services to our customers. We apply mark-to-market accounting for all of our non-asset based energy trading, marketing, power origination and risk management services activities. For information regarding mark-to-market accounting, please read Notes 2(d) and 5 to our consolidated financial statements. These trading and marketing activities consist of:

- the domestic energy trading, marketing, power origination and risk management services operations of our Wholesale Energy business segment;
- the European energy trading and power origination operations of our European Energy business segment; and
- the large contracted commercial, industrial and institutional retail electricity business of our Retail Energy business segment.

Our domestic and European energy trading and marketing operations enter into derivative transactions as a means of optimization of our current power generation asset position and to take a market position. For additional information regarding the types of contracts and activities of our trading and marketing operations, please read "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K and Note 5 to our consolidated financial statements.

Below is a detail of our net trading and marketing assets (liabilities) by business segment:

	As of December 31,	
	2000	2001
	(In millions)	
Wholesale Energy	$31	$154
European Energy	1	(9)
Retail Energy	—	73
Net trading and marketing assets and liabilities	$32	$218

Our trading and marketing and risk management services margins realized and unrealized are as follows:

	For the Year Ended December 31,	
	2000	2001
	(In millions)	
Realized	$202	$184
Unrealized	(2)	186
Total	$200	$370

Below is an analysis of our net trading and marketing assets and liabilities for 2001 (in millions):

Fair value of contracts outstanding at December 31, 2000	$ 32
Fair value of new contracts when entered into during the year	119
Contracts realized or settled during the year	(184)
Changes in fair values attributable to changes in valuation techniques and assumptions	(23)
Changes in fair values attributable to market price and other market changes	274
Fair value of contracts outstanding at December 31, 2001	$ 218

During 2001, our Retail Energy business segment entered into contracts with large commercial, industrial and institutional customers, with a peak demand of approximately 3,700 MW, ranging from one to three years. These contracts had an aggregated fair value of $97 million at the contract inception dates. Subsequent to the inception dates, the fair values of these contracts were adjusted to $74 million due to changes in assumptions used in the valuation models, as described below. The fair value of these Retail Energy electric supply contracts was determined by comparing the contractual pricing to the estimated market price for the retail energy delivery and applying the estimated volumes under the provisions of these contracts. This calculation involves estimating the customer's anticipated load volume, and using the forward ERCOT over-the-counter (OTC) commodity prices, adjusted for the customer's anticipated load pattern. Load characteristics in the valuation model include: the customer's expected hourly electricity usage profile, the potential variability in the electricity usage profile (due to weather or operational uncertainties), and the electricity usage limits included in the customer's contract. In addition, some estimates include anticipated delivery costs, such as regulatory and transmission charges, electric line losses, ERCOT system operator administrative fees and other market interaction charges, estimated credit risk and administrative costs to serve. The weighted-average duration of these transactions is approximately one year.

The remaining fair value of new contracts recorded at inception of $22 million primarily relates to Wholesale Energy fixed and variable-priced power purchases and sales. The fair values of these Wholesale Energy contracts at inception are estimated using OTC forward price and volatility curves and correlation among power and fuel prices, net of estimated credit risk. A significant portion of the value of these contracts required utilization of internal models. For the contracts extending beyond December 31, 2001, the weighted-average duration of these transactions is less than two years.

Below are the maturities of our contracts related to our trading and marketing assets and liabilities as of December 31, 2001 (in millions):

	Fair Value of Contracts at December 31, 2001						
Source of Fair Value	2002	2003	2004	2005	2006	2007 and thereafter	Total fair value
Prices actively quoted	$(43)	$ 4	$ 1	$—	$—	$—	$(38)
Prices provided by other external sources	142	58	(5)	(3)	6	(1)	197
Prices based on models and other valuation methods	34	(1)	3	3	(1)	21	59
Total	$133	$61	$(1)	$—	$ 5	$20	$218

The "prices actively quoted" category represents our New York Mercantile Exchange (NYMEX) futures positions in natural gas and crude oil. As of December 31, 2001, the NYMEX had quoted prices for natural gas and crude oil for the next 36 and 30 months, respectively.

The "prices provided by other external sources" category represents our forward positions in natural gas and power at points for which OTC broker quotes are available. On average, OTC quotes for natural gas and power extend 60 and 36 months into the future, respectively. We value these positions against internally developed forward market price curves that are continuously compared to and recalibrated against OTC broker quotes. This category also includes some transactions whose prices are obtained from external sources and then modeled to hourly, daily or monthly prices, as appropriate.

The "prices based on models and other valuation methods" category contains (a) the value of our valuation adjustments for liquidity, credit and administrative costs, (b) the value of options not quoted by an exchange or OTC broker, (c) the value of transactions for which an internally developed price curve was constructed as a result of the long-dated nature of the transaction or the illiquidity of the market point, and (d) the value of structured transactions. In certain instances structured transactions can be composed and modeled by us as simple forwards and options based on prices actively quoted. Options are typically valued using Black-Scholes option valuation models. Although the valuation of the simple structures might not be different than the valuation of contracts in other categories, the effective model price for any given period is a combination of prices from two or more different instruments and therefore have been included in this category due to the complex nature of these transactions.

The fair values in the above table are subject to significant changes based on fluctuating market prices and conditions. Changes in the assets and liabilities from trading, marketing, power origination and price risk management services result primarily from changes in the valuation of the portfolio of contracts, newly originated transactions and the timing of settlements. The most significant parameters impacting the value of our portfolio of contracts include natural gas and power forward market prices, volatility and credit risk. For the Retail Energy sales discussed above, significant variables affecting contract values also include the variability in electricity consumption patterns due to weather and operational uncertainties (within contract parameters). Market prices assume a normal functioning market with an adequate number of buyers and sellers providing market liquidity. Insufficient market liquidity could significantly affect the values that could be obtained for these contracts, as well as the costs at which these contracts could be hedged. Please read "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K for further discussion and measurement of the market exposure in the trading and marketing businesses and discussion of credit risk management.

For additional information about price volatility and our hedging strategy, please read "— Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Wholesale Energy Operations — Price Volatility," and "— Risks Associated with Our Hedging and Risk Management Activities."

For information regarding our counterparty credit risk, including credit ratings, exposure and collateral held by us, please read, "Quantitative and Qualitative Disclosures About Market Risk — Credit Risk" in Item 7A of this Form 10-K.

For a description of accounting policies for our trading and marketing activities, please read Notes 2(d) and 5 to our consolidated financial statements.

We seek to monitor and control our trading risk exposures through a variety of processes and committees. For additional information, please read "Quantitative and Qualitative Disclosures About Market Risk — Risk Management Structure" in Item 7A of this Form 10-K.

CERTAIN FACTORS AFFECTING OUR FUTURE EARNINGS

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

- state, federal and international legislative and regulatory developments, including deregulation, re-regulation and restructuring of the electric utility industry, changes in or application of environmental and other laws and regulations to which we are subject and changes in or application of laws or regulations applicable to other aspects of our business, such as commodities trading and hedging activities;
- the timing of the implementation of our Business Separation Plan;
- the effects of competition, including the extent and timing of the entry of additional competitors in our markets;
- liquidity concerns in our markets;

- industrial, commercial and residential growth in our service territories;
- the degree to which Reliant Resources successfully integrates the operations and assets of Orion Power into the Wholesale Energy business segment;
- the determination of the amount of our Texas generation business' stranded costs and the recovery of these costs;
- the availability of adequate supplies of fuel, water, and associated transportation necessary to operate our generation facilities;
- our pursuit of potential business strategies, including acquisitions or dispositions of assets or the development of additional power generation facilities;
- state, federal and other rate regulations in the United States and in foreign countries in which we operate or into which we might expand our operations;
- the timing and extent of changes in interest rates and commodity prices, particularly natural gas prices;
- weather variations and other natural phenomena, which can affect the demand for power from, or our ability to produce power at our generating facilities;
- our ability to cost-effectively finance and refinance;
- the degree to which we successfully integrate the operations and assets of Orion Power into our Wholesale Energy segment;
- the successful and timely completion of our construction programs, as well as the successful start-up of completed projects;
- financial market conditions, our access to and cost of capital and the results of our financing and refinancing efforts, including availability of funds in the debt/capital markets for merchant generation companies;
- the credit worthiness or bankruptcy or other financial distress of our trading, marketing and risk management services counterparties;
- actions by rating agencies with respect to us or our competitors;
- acts of terrorism or war;
- the availability and price of insurance;
- the reliability of the systems, procedures and other infrastructure necessary to operate our retail electric business, including the systems owned and operated by ERCOT;
- political, legal, regulatory and economic conditions and developments in the United States and in foreign countries in which we operate or into which we might expand our operations, including the effects of fluctuations in foreign currency exchange rates;
- the resolution of the refusal by California market participants to pay our receivables balances due to the recent energy crisis in the West region; and
- the successful operation of deregulating power markets.

In order to adapt to the increasingly competitive environment in our industry, we continue to evaluate a wide array of potential business strategies, including business combinations or acquisitions involving other utility or non-utility businesses or properties, dispositions of currently owned businesses, as well as developing new generation projects, products, services and customer strategies.

Factors Associated With the Business Separation, Restructuring and Distribution

As previously discussed, in anticipation of electric deregulation in Texas, and pursuant to the Texas Electric Restructuring Law, we submitted a business separation plan in January 2000 to the Texas Utility Commission. Pursuant to the Business Separation Plan, we are in the process of separating our regulated and our unregulated businesses into two separate publicly traded companies.

After the Restructuring, we plan, subject to further corporate approvals, market and other conditions, to complete the separation of our regulated and unregulated businesses through the Distribution. Our goal is to complete the Restructuring and subsequent Distribution as quickly as possible after all the necessary conditions are fulfilled, including receipt of an order from the SEC granting the required approvals under the Public Utility Holding Company Act of 1935 (1935 Act) and an extension from the IRS for a private letter ruling we have obtained regarding the tax-free treatment of the Distribution. We currently expect to complete the Restructuring and Distribution in the summer of 2002. See "Our Business — Business Separation" in Item 1 of this Form 10-K.

Regulatory Uncertainty. The Restructuring as currently planned cannot be completed unless and until the SEC issues an order approving the acquisition by CenterPoint Energy of Reliant Energy and its subsidiary companies and either granting CenterPoint Energy an exemption from regulation as a registered public utility holding company under the 1935 Act or the necessary authority to operate as a registered holding company. While we believe such an order will be received, and that both the Restructuring and Distribution will be completed during the summer of 2002, there can be no assurances that such will be the case. The Restructuring has been designed to enable us to meet all of the requirements of the Texas Electric Restructuring Law. We have not formulated an alternative restructuring plan that could be implemented if the SEC fails or refuses to grant an exemption for CenterPoint Energy or the authority for CenterPoint Energy to become a registered holding company on terms consistent with our business plan. For information about an informal inquiry by the staff of the Division of Enforcement of the SEC in connection with an earnings restatement by Reliant Energy that might impact the approval process, please read "Restatement of Second and Third Quarter 2001 Results of Operations" in Item 3 of this Form 10-K.

The tax ruling that we received from the IRS expires at the end of April 2002. We are currently seeking an extension of this ruling from the IRS. There can be no assurance that we will receive the extension quickly or at all. In this event, the Restructuring and Distribution are not likely to be completed within our expected time frame, or, perhaps, at all. In addition, our tax ruling contemplates that the Restructuring will occur prior to the Distribution. If, due to delay or uncertainty regarding receipt of an order under the 1935 Act, we decide to make the Distribution before completing the Restructuring, we would have to seek a new ruling from the IRS that the Distribution would be tax free to us and to our shareholders. This process could take six months or longer.

A significant delay in completing the Restructuring and the Distribution may impact planned financings by each of Reliant Energy and Reliant Resources and make it more difficult and more expensive for us to obtain bank financing. We cannot predict how any such delay might impact our credit ratings or those of Reliant Resources.

Adverse Tax Consequences. If we take actions which cause the Distribution to fail to qualify as a tax-free transaction, we will incur taxable gain equal to the positive difference between the value of the Reliant Resources shares distributed and our tax basis in those shares. Current tax law provides that, depending on the facts and circumstances, the Distribution may be taxable if either CenterPoint Energy or Reliant Resources undergo a 50% or greater change in stock ownership within two years after the Distribution. These costs may be so great that they delay or prevent a strategic acquisition or change in control of our company. If Reliant Resources takes actions which cause the Distribution to fail to qualify as a tax-free transaction, for example, through a change in control of Reliant Resources, we will be responsible for the tax due on the gain but may seek indemnity from Reliant Resources for such payments.

Credit. To the extent that we continue to need access to current amounts of committed credit prior to the Distribution, we expect to extend or replace the credit facilities on a timely basis. The terms of any new

credit facilities are expected to be adversely affected by our leverage, the amount of bank capacity utilized, any delay in the date of Restructuring and Distribution and conditions in the bank market. These same factors are expected to make the syndication of new credit facilities more difficult in the future. Proceeds from any issuance of debt in the capital markets are expected to be used to retire a portion of our short-term debt and reduce our need for committed revolving credit facilities.

Factors Affecting the Results of Our Electric Operations

Deregulation. In June 1999, the Texas legislature adopted the Texas Electric Restructuring Law, which substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail competition. Retail pilot projects for up to 5% of each utility's load in all customer classes began in August 2001 and retail electric competition for all other customers began on January 1, 2002. We have made significant changes in the electric utility operations previously conducted through Reliant Energy HL&P. For additional information regarding these changes, please read "Our Business — Deregulation," "— Electric Operations," "— Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" and "— Our Business Going Forward" in Item 1 of this Form 10-K and Note 4 to our consolidated financial statements.

Transmission and Distribution. Under the Texas Electric Restructuring Law, our T&D Utility will remain subject to traditional rate regulation by the Texas Utility Commission, and we will collect from retail electric providers the rates approved in the T&D Utility's rate case (Wires Case) to cover the cost of providing transmission and distribution service and any other expenses. Our ability to earn the rate of return built into the T&D Utility's rates may be affected, positively or negatively, to the extent that the T&D Utility's actual expenses or revenues differ from the estimates used to set the T&D Utility's rates.

Generation. As described under "Electric Operations — Generation," since January 1, 2002, we have been obligated to sell substantially all of the generating capacity and related ancillary services of our Texas generation business through auctions. As a result, we are not guaranteed any rate of return on our investment in these generation facilities through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for electricity in the Texas market and the related results of our capacity auctions. These market prices may fluctuate substantially over relatively short periods of time. In addition, ERCOT, the independent system operator for the Texas markets, may impose price limitations, bidding rules and other mechanisms that may impact wholesale power prices in the Texas market and the outcome of our capacity auctions. Our historical financial results represent the results of our Texas generation business as part of an integrated utility in a regulated market and may not be representative of its results as a stand-alone wholesale electric power generation company in an unregulated market. Therefore, the historical financial information included in this report does not necessarily reflect what our financial position, results of operations and cash flows would have been had our generation facilities been operated in an unregulated market.

Under the terms of the auctions pursuant to which we are obligated to sell our capacity, we are obligated to provide specified amounts of capacity to successful bidders. The products we sell in the auctions are only entitlements to capacity dispatched from our units and do not convey the right to have power dispatched from a particular unit. This flexibility exposes us to the risk that, depending on the availability of our units, we could be required to supply energy from a higher cost unit to meet an obligation for lower cost generation or to obtain the energy on the open market. Obtaining such replacement generation could involve significant additional costs. We manage this risk by maintaining appropriate reserves within our generation asset base but these reserves may not cover an entire exposure in the event of a significant outage at one of our facilities. For information about operating risks associated with our Texas generation business, please read "Factors Affecting the Results of Our Wholesale Energy Operations — Operating Risks" below.

Also, market volatility in the price of fuel for our generation operations, as well as in the price of purchased power, could have an effect on our cost to generate or acquire power. For additional information regarding commodity prices and supplies, please read "— Factors Affecting the Results of Our Wholesale Energy Operations — Price Volatility."

Pursuant to the Texas Electric Restructuring Law, we will be entitled to recover our stranded costs (i.e., the excess of regulatory net book value of generation assets, as defined by the Texas Electric Restructuring Law, over the market value of those assets) and our regulatory assets related to generation. The Texas Electric Restructuring Law prescribes specific methods for determining the amount of stranded costs and the details for their recovery, and our recovery of stranded costs is dependent upon the outcome of regulatory proceedings in which we will be required to establish the extent of our stranded costs and related underlying matters. During the base rate freeze period from July 1999 through 2001, earnings above the utility's authorized rate of return formula were applied in a manner to accelerate depreciation of generation related plant assets for regulatory purposes. In addition, depreciation expense for transmission and distribution related assets was redirected to generation assets for regulatory purposes from 1998. The Texas Electric Restructuring Law also provided for us, or a special purpose entity formed by us, to issue securitization bonds for the recovery of generation related regulatory assets and a portion of stranded costs. Reliant Energy Transition Bond Company LLC, our wholly owned subsidiary, issued $749 million of securitization bonds on October 24, 2001. Any stranded costs not recovered through the sale of securitization bonds may be recovered through a charge to transmission and distribution customers. For additional information regarding these securitization bonds, please read Note 4(a) to our consolidated financial statements. For information regarding recovery of under-collected fuel expenses, please read "Liquidity and Capital Resources — Future Sources and Uses of Cash — Fuel Filing in Item 7 of this Form 10-K".

The Texas Utility Commission issued a final order on October 3, 2001 (October 3, 2001 Order) that established the transmission and distribution rates that became effective January 2002. In this Order, the Texas Utility Commission found that we had overmitigated our stranded costs by redirecting transmission and distribution depreciation and by accelerating depreciation of generation assets as provided under the Transition Plan and Texas Electric Restructuring Law. In December 2001, we recorded a regulatory liability of $1.1 billion to reflect the prospective refund of accelerated depreciation, removed our previously recorded embedded regulatory asset of $841 million related to redirected depreciation and recorded a regulatory asset of $2.0 billion based upon current projections of market value of the Reliant Energy HL&P generation assets to be covered by the 2004 true-up proceeding provided for in the Texas Electric Restructuring Law. Recovery of this asset is subject to regulatory risk. We began refunding the excess mitigation credits in January 2002 and will continue over a seven year period. If events occur that make the recovery of all or a portion of the regulatory assets no longer probable, we will write off the corresponding balance of these assets as a charge against earnings. One of the results of discontinuing the application of regulatory accounting for the generation operations is the elimination of the regulatory accounting effects of excess deferred income taxes and investment tax credits related to these operations. We believe it is probable that some parties will seek to return these amounts to ratepayers and, accordingly, we have recorded an offsetting liability.

The Texas Electric Restructuring Law requires us to auction 15% of the output of the installed generating capacity of our Texas generation business until January 1, 2007 unless certain criteria are met (state mandated auctions). In addition, the master separation agreement between Reliant Energy and Reliant Resources requires us to auction to third parties, including Reliant Resources, the capacity available in excess of amounts included in the state mandated auctions (contractually mandated auctions). Beginning January 2002, our Texas generation business began delivering power sold through the state mandated auctions and contractually mandated auctions at market rates. However, the Texas Electric Restructuring Law provides for recovery of any difference between market power prices received in these capacity auctions and the Texas Utility Commission's earlier estimates of those market prices. This capacity auction true-up should provide for revenues earned by our Texas generation business during the two-year period ending December 2003 to approximate a regulated return on the invested capital of our Texas generation business. The Texas Utility Commission's estimate serves as a preliminary identification of stranded costs for recovery through securitization. This component of the true-up is intended to ensure that neither the customers nor we are disadvantaged economically as a result of the two-year transition period by providing this pricing structure. The underlying data for the true-up calculation has not been finalized. Because the capacity true-up process provided for in the Texas Electric Restructuring Law will take into account only the prices we receive in the state mandated auctions, lower prices that we may receive in the contractually mandated auctions will not be considered and

we may therefore not recover all of our stranded costs. We cannot predict the amount, if any, of these costs that would not be recovered.

Retail. For a discussion of factors affecting our retail operations, please read "— Factors Affecting the Results of Our Retail Operations."

Other. For additional information regarding litigation over franchise fees, please read Note 14(f) to our consolidated financial statements.

Factors Affecting the Results of RERC's Operations

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

Generally, the regulations of the states in which our Natural Gas Distribution business segment operates allow us to pass through changes in the costs of natural gas to our customers through purchased gas adjustment provisions in rates. There is, however, an inherent timing difference between our purchases of natural gas and the ultimate recovery of these costs. Consequently, we may incur additional "carrying" costs as a result of this timing difference and the resulting, temporary under-recovery of our purchased gas costs. To a large extent, these additional carrying costs are not recovered from our customers.

On November 21, 2001, Arkla filed a rate case (Docket 01-243-U) with the Arkansas Public Service Commission seeking an increase in rates for its Arkansas customers of approximately $47 million on an annual basis. Arkla's last rate increase was authorized in 1995. In the rate filing, Arkla maintains that its rate base has grown by $183 million, and its operating expenses have increased from $93 million to $106 million on an annual basis and, therefore, Arkla's current rates for service to Arkansas customers do not provide a reasonable opportunity for Arkla to cover its operating costs and earn a fair return on its investment. A decision in the case is expected by the fourth quarter of 2002.

Pipelines and Gathering. Our Pipelines and Gathering business segment competes with other interstate and intrastate pipelines in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service, and flexibility and reliability of service. Our Pipelines and Gathering business segment competes indirectly with other forms of energy available to its customers, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability of energy and pipeline capacity, the level of business activity, conservation and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas in areas we serve and the level of competition for transportation and storage services. Since FERC Order No. 636, REGT's and MRT's commodity sales activity has been minimal. Commodity transactions are usually related to system management activity which we have been able to manage with little exposure. We have not been nor do we anticipate being negatively impacted by higher price levels and the tightening of supply experienced in the fourth quarter of 2000 and the first quarter of 2001. In addition, competition for our gathering operations is impacted by commodity pricing levels in its markets because these prices influence the level of drilling activity in those markets.

Natural Gas Pipeline Company of America has proposed, and is soliciting customers for a 30" pipeline paralleling MRT's East Line in Illinois to a point 17 miles east of St. Louis Metro, with a proposed in-service date of June 2002. This service would represent an alternative to that provided by MRT. MRT has renewed or is engaged in negotiations to renew service agreements under multi-year terms, including service and potential expansion needs along MRT's existing East Line in Illinois. Our Pipelines and Gathering business segment derives approximately 14% of its revenues from Laclede Gas Company, which has an annual evergreen term provision. In February 2002, MRT negotiated an agreement to extend its existing service relationship with Laclede for a five year period subject to acceptance by the FERC. However, the Pipelines and Gathering

business segment's financial results could be materially adversely affected after this five year period if Laclede decides to engage another pipeline for the transportation services currently provided by the Pipelines and Gathering business segment.

Factors Affecting the Results of Our Wholesale Energy Operations

Price Volatility. Our Wholesale Energy business segment, which is conducted through Reliant Resources, sells electricity from its facilities into spot markets under short- and long-term contractual arrangements. We are not guaranteed any rate of return on our capital investments through cost of service rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for electricity and fuel in our regional markets. In addition to our power generation operations, we trade and market power. Market prices may fluctuate substantially over relatively short periods of time. Demand for electricity can fluctuate dramatically, creating periods of substantial under- or over-supply. During periods of over-supply, prices are depressed. During periods of under-supply, there is frequently regulatory or political pressure to regulate prices to compensate for product scarcity.

In addition, the FERC, which has jurisdiction over wholesale power rates, as well as independent system operators that oversee some of these markets, have imposed price limitations, bidding rules and other mechanisms to attempt to address some of the volatility in these markets and mitigate market prices. For a discussion of the implementation of price limitations and other rules in the California market, please read Note 14(g) to our consolidated financial statements.

Most of our Wholesale Energy business segment's domestic power generation facilities purchase fuel under short-term contracts or on the spot market. Fuel prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel costs. In addition, we trade and market natural gas and other energy-related commodities. These factors could have an adverse impact on our revenues, margins and results of operations.

Volatility in market prices for fuel and electricity may result from:

- weather conditions;
- seasonality;
- forced or unscheduled plant outages;
- addition of generating capacity;
- changes in market liquidity;
- disruption of electricity or gas transmission or transportation, infrastructure or other constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities and general economic conditions;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, embargoes and other catastrophic events; and
- federal, state and foreign governmental regulation and legislation.

Risks Associated with Our Hedging and Risk Management Activities. To lower our financial exposure related to commodity price fluctuations, our trading, marketing and risk management services operations routinely enter into contracts to hedge a portion of our purchase and sale commitments, exposure to weather fluctuations, fuel requirements and inventories of natural gas, coal, crude oil and refined products, and other commodities. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps and option contracts traded in the over-the-counter markets and on exchanges. However, we do not expect to cover the entire exposure of our assets or our positions to market price volatility, and the coverage will vary over time. This hedging activity fluctuates according to strategic objectives, taking into account the desire for cash flow or earnings certainty and our view on market prices. To the extent we have unhedged positions, fluctuating commodity prices could negatively impact our financial

results and financial position. For additional information regarding the accounting treatment for our hedging, trading and marketing and risk management activities, please read Notes 2(d) and 5 to our consolidated financial statements. For additional information regarding the types of contracts and activities of our trading and marketing operations, please read "— Trading and Marketing Operations" and "Qualitative and Quantitative Disclosures about Market Risk" in Item 7A of this Form 10-K.

We manage our power generation hedge objectives in the context of market conditions while targeting certain hedge percentages of future earnings through hedge actions in the current year. As of December 31, 2001, we had hedged 39% and 29% of our planned Wholesale Energy margins for 2002 and 2003, respectively, excluding margins related to Orion Power. Margins for 2002 and 2003 are expected to be positively impacted by the acquisition of Orion Power and negatively affected by lower forward electric power prices as they relate to unhedged positions and an estimated decline in our trading and marketing operations due to projected decreases in volatility in energy commodity markets.

At times, we have open trading positions in the market, within established corporate risk management guidelines, resulting from the management of our trading portfolio. To the extent open trading positions exist, changes in commodity prices could negatively impact our financial results and financial position.

The risk management procedures we have in place may not always be followed or may not always work as planned. As a result of these and other factors, we cannot predict with precision the impact that our risk management decisions may have on our businesses, operating results or financial position. For information regarding our risk management policies, please read "Quantitative and Qualitative Disclosures about Market Risk — Risk Management Structure" in Item 7A to this Form 10-K.

The trading, marketing and risk management services operations conducted by our Wholesale Energy business segment are also exposed to the risk that counterparties who owe us money or physical commodities, such as power, natural gas or coal, will not perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to acquire alternative hedging arrangements or replace the underlying commitment at then-current market prices. In this event, we might incur additional losses to the extent of amounts, if any, already paid to the counterparties. For information regarding our credit risk, including exposure to Enron and utilities in California, please read "Quantitative and Qualitative Disclosure About Market Risk — Credit Risk" in Item 7A of this Form 10-K and Notes 5(c), 14(g) and 21 to our consolidated financial statements.

In the ordinary course of business, and as part of our hedging strategy, we enter into long-term sales arrangements for power, as well as long-term purchase arrangements. For information regarding our long-term fuel supply contracts, purchase power and electric capacity contracts and commitments, electric energy and electric sale contracts and tolling arrangements, please read Notes 5, 14(a) and 14(b) to our consolidated financial statements.

Uncertainty in the California Market. During portions of 2000 and 2001, prices for wholesale electricity in California increased dramatically as a result of a combination of factors, including higher natural gas prices and emission allowance costs, reduction in available hydroelectric generation resources, increased demand, decreased net electric imports and limitations on supply as a result of maintenance and other outages. Because of the high prices that prevailed during this period, we, and several of Reliant Resources' subsidiaries, including Reliant Energy Services and REPG, as well as some of the officers of some of these companies, have been named as defendants in class action lawsuits and other lawsuits filed against a number of companies that own generation plants in California and other sellers of electricity in California markets.

In response to the filing of a number of complaints challenging the level of these wholesale prices, the FERC initiated a staff investigation and issued a number of orders implementing a series of wholesale market reforms and modifications to those reforms. On February 13, 2002, the FERC issued an order initiating a staff investigation into potential manipulation of electric and natural gas prices in the West region for the period January 1, 2000 forward. Some of our long-term bilateral contracts already have been challenged by one of our many counterparties based on the alleged market dysfunction in Western power markets in 2000 and 2001. If these challenges are successful, the precedent set by the challenge could have larger ramifications to our

business and operations beyond the challenged contracts at issue. Furthermore, in addition to FERC investigations, several state and other federal regulatory investigations have commenced in connection with the wholesale electricity prices in California and other neighboring Western states to determine the causes of the high prices and potentially to recommend remedial action.

Finally, there have been proposals in the California state legislature to regulate the operations of our California generating subsidiaries, beyond the existing state regulation regarding siting, environmental and other health and safety matters. For additional information regarding the litigation and market uncertainty in California, please read Notes 14(f) and 14(g) to our consolidated financial statements.

Industry Restructuring, the Risk of Re-regulation and the Impact of Current Regulations. The regulatory environment applicable to the United States electric power industry is undergoing significant changes as a result of varying restructuring initiatives at both the state and federal levels and the reassessment of existing regulatory mechanisms stemming from the California power market situation and the bankruptcy of Enron. These initiatives have had a significant impact on the nature of the industry and the manner in which its participants conduct their business. These changes are ongoing and we cannot predict the future development of restructuring in these markets or the ultimate effect that this changing regulatory environment will have on our business.

Moreover, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us, our facilities or our commercial activities, and future changes in laws and regulations may have a detrimental effect on our business. Some restructured markets, particularly California, have experienced supply problems and price volatility. These supply problems and volatility have been the subject of a significant amount of press coverage, much of which has been critical of the restructuring initiatives. In some markets, including California, proposals have been made by governmental agencies and/or other interested parties to delay or discontinue proposed restructuring or to re-regulate areas of these markets, especially with respect to residential retail customers, that have previously been deregulated. In this connection, state officials, the California Independent System Operator (Cal ISO) and the investor-owned utilities in California have argued to the FERC that our California generating subsidiaries should not continue to have market-based rate authority. While the FERC to date has consistently refused petitions to force entities with market-based rates to return to cost-based rates, some of these proceedings are ongoing and we cannot predict what action the FERC may take on such petitions in the future. If we were forced to adopt cost-based rates, future earnings would be affected. Furthermore, the Cal ISO is undertaking a market redesign process to fundamentally change the structure of wholesale electricity markets and transmission service in California. These changes, if approved by the FERC, could include a revised market monitoring and mitigation structure, a revised congestion management mechanism and an obligation for load-serving entities in California to maintain capacity reserves. The Cal ISO's stated goal is to complete the first phase of this redesign by September 30, 2002, when the existing FERC market mitigation scheme for California will expire.

On November 20, 2001, the FERC instituted an investigation under Section 206 of the Federal Power Act regarding the tariffs of all sellers with market-based rates authority, including Reliant Energy. For information regarding this FERC proceeding and other FERC actions relating to the California market, please read Note 14(g) to our consolidated financial statements. If the FERC does not modify or reject its proposed approach for dealing with anti-competitive behavior, our future earnings may be affected by the open-ended refund obligation.

Additionally, federal legislative initiatives have been introduced and discussed to address the problems being experienced in some of these markets, including legislation seeking to impose price caps on sales. We cannot predict whether other proposals to re-regulate will be made or whether legislative or other attention to the restructuring of the electric power industry will cause the restructuring to be delayed or reversed. If the trend towards competitive restructuring of the wholesale power markets is reversed, discontinued or delayed, the business growth prospects and financial results of our Wholesale Energy and Retail Energy segments could be adversely affected.

If RTOs are established as envisioned by Order No. 2000, "rate pancaking," or multiple transmission charges that apply to a single point-to-point delivery of energy will be eliminated within a region, and

wholesale transactions within the region, and between regions will be facilitated. The end result could be a more competitive, transparent market for the sale of energy and a more economic and efficient use and allocation of resources; however, considerable opposition exists to the development of RTOs.

The FERC also has initiated a rulemaking proceeding to establish standardized transmission service throughout the United States, a standard wholesale electric market design, including forward and spot markets for energy and an ancillary services market, and specifications regarding the entities that administer these markets and for market monitoring and mitigation, that could be used in all RTOs. We cannot predict at this time what effect FERC's standard market design will have on our business growth prospects and financial results.

Partly in response to the bankruptcy of Enron, there have been proposals in the United States Congress to make online platforms that trade energy and metals derivatives subject to oversight by the Commodities Futures Trading Commission (CFTC), to prohibit market price manipulation and fraud. Under some of these proposals, dealers in energy derivatives would be required to file reports with the CFTC and maintain amounts of capital, as determined by the CFTC, to support the risks of their transactions. Other proposals would require the CFTC to review these markets for potential regulatory recommendations. We do not know what impact, if any, these proposals would have on our business if enacted. Additionally, there may be other broader proposals introduced to submit energy trading to comprehensive regulation by the FERC or by the CFTC.

The acquisition, ownership and operation of power generation facilities require numerous permits, approvals and certificates from federal, state and local governmental agencies. The operation of our generation facilities must also comply with environmental protection and other legislation and regulations. At present, we have operations in Arizona, California, Florida, Illinois, Maryland, Nevada, New Jersey, New York, Ohio, Pennsylvania, Texas and West Virginia. Most of our existing domestic generation facilities are exempt wholesale generators that sell electricity exclusively into the wholesale market. These facilities are subject to regulation by the FERC regarding rate matters and by state public utility commissions regarding siting, environmental and other health and safety matters. The FERC has authorized us to sell our generation from these facilities at market prices. The FERC retains the authority to modify or withdraw our market-based rate authority and to impose "cost of service" rates if it determines that market pricing is not in the public interest.

Uncertainty Related to the New York Regulatory Environment. The New York market is subject to significant regulatory oversight and control. Our operating results are as dependent on the continuance of the regulatory structure as they are on fluctuations in the market price for electricity. The rules governing the current regulatory structure are subject to change. We cannot assure you that we will be able to adapt our business in a timely manner in response to any changes in the regulatory structure, which could have a material adverse effect on our revenues and costs. The primary regulatory risk in this market is associated with the oversight activity of the New York Public Service Commission, the New York Independent System Operator (NYISO) and the FERC.

Our assets located in New York are subject to "lightened regulation" by the New York Public Service Commission, including provisions of the New York Public Service Law that relate to enforcement, investigation, safety, reliability, system improvements, construction, excavation, and the issuance of securities. Because "lightened regulation" was accomplished administratively, it could be revoked.

The NYISO has the ability to revise wholesale prices, which could lead to delayed or disputed collection of amounts due to us for sales of energy and ancillary services. The NYISO also has the ability, in some cases subject to FERC approval, to impose cost-based pricing and/or price caps. The NYISO has implemented a measure known as the "Automated Mitigation Procedure" (AMP) under which day-ahead energy bids will be automatically reviewed and, if necessary, mitigated if economic or physical withholding is determined. Proposed modifications to the AMP provide a level of uncertainty over the impacts of that procedure in the summer of 2002. FERC has also directed the NYISO to adopt mitigation measures for all limits in New York City consistent with its overall market-monitoring plan. NYISO has filed in-city mitigation measures with the FERC, which it is proposing to be implemented beginning in late spring of 2002. The full impact of these revisions may not be known until the summer of 2002.

Integration and Other Risks Associated with Our Orion Power Assets. We have made a substantial investment in our recent acquisition of Orion Power. If we are unable to profitably integrate, operate, maintain and manage our newly acquired power generation facilities our results of operations will be adversely affected.

Duquesne Light Company is obligated to supply electricity at predetermined tariff rates to all retail customers in its existing service territory who do not select another electricity supplier. Orion Power has committed to provide 100% of the energy that Duquesne Light Company needs to meet this obligation under a contract that was recently extended through December 2004. If our obligation under this contract exceeds the available output from the combination of Orion Power's generation facilities and our additional generation facilities in the region, we would be forced to buy additional energy at prevailing market prices and, in certain cases where we failed to deliver the required amount, we could incur penalties during periods of peak demand of up to $1,000 per megawatt hour. If this situation were to occur during periods of peak energy prices, we could suffer substantial losses that could materially adversely affect our results of operations. In addition, our revenues generated under this contract may be adversely impacted if a substantial number of Duquesne Light Company's retail customers select other retail electric providers.

Operating Risks. Our Electric Generation, Wholesale Energy operations and our European Energy operations are exposed to risks relating to the breakdown or failure of equipment or processes, fuel supply interruptions, shortages of equipment, material and labor, and operating performance below expected levels of output or efficiency. A significant portion of our facilities were constructed many years ago. Older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to add or upgrade equipment to keep it operating at peak efficiency, to comply with changing environmental requirements, or to provide reliable operations. Such changes could affect operating costs. Any unexpected failure to produce power, including failure caused by breakdown or forced outage, could result in reduced earnings.

We depend on transmission and distribution facilities owned and operated by utilities and other power companies to deliver the electricity we sell from our power generation facilities to our customers, who in turn deliver these products to the ultimate consumers of the power. If transmission is disrupted, or transmission capacity is inadequate, our ability to sell and deliver our products may be hindered.

Factors Affecting Our Acquisition and Project Development Activities. Our plans for our Wholesale Energy business segment indicate a shift in emphasis from identifying and pursuing acquisition and development candidates to construction and integration of generation facilities. We believe this is a temporary shift based on the requirements of integrating the Orion Power assets and the maturation of both our and Orion Power's development projects and by the current state of the wholesale electricity and capital markets.

There are numerous risks relating to the acquisition and development of power generation plants and construction and integration of these facilities. We may not be able to identify attractive acquisitions or development opportunities, complete acquisitions or development projects we undertake, or we may not be able to integrate these plants, especially larger acquisitions, into the portfolios of our Wholesale Energy business segment and achieve the synergies, including cost savings, we originally envisioned.

Currently, our Wholesale Energy business segment has a select number of power generation facilities under development and many under construction (either owned or leased). Our completion of these facilities is subject to the following:

- market prices;
- shortages and inconsistent quality of equipment, material and labor;
- financial market conditions and the results of our financing efforts;
- actions by rating agencies with respect to us or our competitors;
- work stoppages, due to plant bankruptcies and contract labor disputes;
- permitting and other regulatory matters;

- unforeseen weather conditions;
- unforeseen equipment problems;
- environmental and geological conditions; and
- unanticipated capital cost increases.

Any of these factors could give rise to delays, cost overruns or the termination of the plant expansion, construction or development. Many of these risks cannot be adequately covered by insurance. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet specified performance standards, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover lost revenues, increased expenses or liquidated damages payments we may owe.

If we were unable to complete the development of a facility, we would generally not be able to recover our investment in the project. The process for obtaining initial environmental, siting and other governmental permits and approvals is complicated, expensive, lengthy and subject to significant uncertainties. Transmission interconnection, fuel supply and cooling water represent some cost uncertainties during project development that may also result in termination of the project. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect our results of operations. The failure to complete construction according to specifications can result in liabilities, reduced plant efficiency, higher operating costs and reduced earnings. We may not be successful in the development or construction of power generation facilities in the future.

As a result of several recent events, including the United States economic recession, the price decline of our industry sector in the equity capital markets and the downgrading of the credit ratings of several of our significant competitors, the availability and cost of capital for our business and the businesses of our competitors has been adversely affected. In response to these events and the intensified scrutiny of companies in our industry sector by the rating agencies, our Wholesale Energy business segment has reduced its planned capital expenditures by $2.7 billion over the 2002-2006 time frame.

Successful integration of plants, especially acquisitions, is subject to a number of risks, including the following:

- unforeseen liabilities or other exposures;
- inaccurate due diligence of acquired facilities, such as underestimates of outage rates and operating costs;
- inability to achieve adequate cost savings in both overhead and operations;
- inability to achieve various commercial synergies with existing operations; and
- market prices for power and fuels.

Any of these factors could significantly affect the economic impact of an acquisition on our results of operations.

As part of this integration process and our temporary shift in emphasis, the Orion Power plants will be part of an operations improvement process that strives to achieve both reduced operating and maintenance costs and increase gross margins through improved availability and reliability of plants. This process is currently underway at our other plants and will be introduced at the Orion Power facilities beginning in the third quarter of 2002.

Increasing Competition in Our Industry. Our Wholesale Energy business segment competes with other energy merchants. In order to successfully compete, we must have the ability to aggregate supplies at competitive prices from different sources and locations and must be able to efficiently utilize transportation services from third-party pipelines and transmission services from electric utilities. We also compete against other energy merchants on the basis of our relative skills, financial position and access to credit sources. Energy customers, wholesale energy suppliers and transporters often seek financial guarantees and other

assurances that their energy contracts will be satisfied. As pricing information becomes increasingly available in the energy trading and marketing business, we anticipate that our operations will experience greater competition and downward pressure on per-unit profit margins. Furthermore, demands for liquidity to support trading and merchant asset businesses are increasing at the same time that the credit rating agencies are reviewing the liquidity and other credit criteria for trading, marketing and merchant generation firms. Other companies we compete with may not have similar credit ratings pressure or may have higher credit ratings. The growth of electronic trading platforms has increased the number of transactions, potential counterparties and level of price transparency in the energy commodity market. As a result, we are likely to transact with a wide range of customers potentially increasing our risk due to their changing credit circumstances, while at the same time potentially diversifying our reliance on a smaller number of customers.

Developments with respect to our competitors frequently have a collateral and tangible impact on us. Credit and liquidity concerns impact our ability to do business with counterparties. Adverse regulatory and political ramifications can result from activities and investigations directed at our competitors.

Hydroelectric Facilities Licensing. The Federal Power Act gives the FERC exclusive authority to license non-federal hydroelectric projects on navigable waterways and federal lands. The FERC hydroelectric licenses are issued for terms of 30 to 50 years. Some of the hydroelectric facilities in our Wholesale Energy business segment, representing approximately 90 MW of capacity, have licenses that expire within the next ten years. Facilities that we own representing approximately 160 MW of capacity have new or initial license applications pending before the FERC. Upon expiration of a FERC license, the federal government can take over the project and compensate the licensee, or the FERC can issue a new license to either the existing licensee or a new licensee. In addition, upon license expiration, the FERC can decommission an operating project and even order that it be removed from the river at the owner's expense. In deciding whether to issue a license, the FERC gives equal consideration to a full range of licensing purposes related to the potential value of a stream or river. It is not uncommon for the relicensing process to take between four and ten years to complete. Generally, the relicensing process begins at least five years before the license expiration date and the FERC issues annual licenses to permit a hydroelectric facility to continue operations pending conclusion of the relicensing process. We expect that the FERC will issue to us new or initial hydroelectric licenses for all the facilities with pending applications. Presently, there are no applications for competing licenses and there is no indication that the FERC will decommission or order any of the projects to be removed.

Factors Affecting the Results of Our European Energy Operations

General. Our European Energy segment, which is operated by subsidiaries of Reliant Resources, intends to focus its activities in existing trading markets in the Netherlands, the United Kingdom, Germany, the Scandinavian countries, Austria and Switzerland. Historical results of operations may not be indicative of future results of operations. In particular, results of operations for our European Energy segment prior to 2001 reflect the impact of a regulated generation price system that has been discontinued. In addition, in 2001 and prior years, under Dutch corporate income tax laws, the earnings of REPGB were subject to a zero percent Dutch corporate income tax rate as a result of the Dutch tax holiday applicable to its electric industry. After December 31, 2001, all of European Energy's earnings in the Netherlands will be subject to the standard Dutch corporate income tax rate, which currently is 34.5%. Furthermore, European Energy's results of operations for 2001 include the effect of a number of non-recurring items, including the $37 million net gain resulting from the settlement of a stranded cost indemnity agreement.

Future results of operations of our European Energy segment could be affected by, among other things, the following:

- increasing competition in the Dutch wholesale energy market, resulting in declining electric power margins;
- the timing and pace of the deregulation of other sectors of the European energy markets;
- the continuing negative impact of the bankruptcy of Enron on market liquidity and credit requirements in European trading markets;

- the mark-to-market price risk exposure associated with certain stranded cost electricity and natural gas supply contracts;
- the impact of any renegotiation of European Energy's stranded cost contracts;
- the impact and changes of natural gas tariffs pursuant to changes in the regulatory structure;
- the ability to negotiate new contracts or renew contracts with customers on favorable terms; and
- the impact of slowing economic growth on power generation demand in the markets in which our European Energy segment operates.

Competition in the European Market. Competition for energy customers in the markets in which our European Energy segment operates is high. The primary factors affecting our European Energy segment's competitive position are price, regulation, the economic resources of its competitors, and its market reputation and perceived creditworthiness.

Our European Energy segment competes in the Dutch Wholesale market against a variety of other companies, including other Dutch generation companies, cogenerators, various producers of alternate sources of power and non-Dutch generators of electric power, primarily from France and Germany. As of December 31, 2001, the Dutch electricity system had three operational interconnection points with Germany and two interconnection points with Belgium. There are also a number of projects that are at various stages of development and that may increase the number of interconnections in the future (post 2005), including interconnections with Norway and the United Kingdom. The Belgian interconnections are primarily used to import electricity from France, but a larger portion of Dutch electricity imports comes from Germany. It is anticipated that over time, transmission constraints between the Netherlands and other European markets will be reduced, thereby exposing our European Energy segment to even greater competitive pressures.

Our European Energy segment's trading and marketing operations are also subject to increasing levels of competition. Competition among power generators for customers is intense and is expected to increase as more participants enter increasingly deregulated markets. Many of our European Energy segment's existing competitors have geographic market positions far more extensive than that of our European Energy segment. In addition, many of these competitors possess significantly greater financial, personnel and other resources than our European Energy segment.

Deregulation of the Dutch Market. The Dutch wholesale electric market was completely opened to competition on January 1, 2001. Consistent with our expectations at the time we acquired our operations in the Netherlands, the gross margin of our European Energy segment declined in 2001 as a result of the deregulation of the market and the termination of an agreement with the other Dutch generators and the Dutch distributors. Commercial markets were generally opened to retail competition in January 2002. We expect the remainder of the market, consisting of mainly residential customers, will be open to competition by January 1, 2003. The timing of opening of the residential segment of the market is subject to change, however, at the discretion of the Dutch Minister of Economic Affairs. Since our European Energy segment's operations focus on the wholesale market, we do not expect that the opening of the Dutch commercial or residential electric market will have a significant impact on the segment's results of operations.

Plant Outages. During 2001, our margins were negatively impacted by unplanned outages at some of our Dutch generation facilities. The unplanned outages were primarily due to malfunctions of the generation turbines and related equipment and complications encountered in the maintenance of one of our facilities. We estimate that these unplanned outages resulted in losses of approximately $11 million, a significant portion of which is covered by property damage and business interruption insurance. For additional information regarding operational risks applicable to our European Energy segment, including unplanned plant outages, please read "— Factors Affecting the Results of Our Wholesale Energy Operations — Operating Risks."

Other Factors. In December 2001, REPGB and its former shareholders entered into a settlement agreement resolving the former shareholders' stranded cost indemnity obligations under the purchase agreement of REPGB. For additional information regarding the stranded cost indemnity settlement and the potential impact on earnings from changes in the valuation in the future of the related stranded cost contracts,

please read Notes 5(b) and 14(h) to our consolidated financial statements. We have begun discussions with the other parties to these contracts to modify the terms of certain of the out-of-market contracts. The structure of these settlements, if consummated, likely would entail an upfront cash payment to the counterparty in exchange for amendments to price and other terms intended to make the contracts more market conforming. REPGB would seek to fund these payments, if made, to the extent possible through the proceeds from the settlement of its stranded cost indemnity agreement and, possibly, anticipated distributions from NEA. We cannot currently predict the outcome of these negotiations. However, to the extent that these discussions result in amendments to the contracts, we could realize a gain.

We are in the process of reviewing our European Energy segment's goodwill and certain intangibles for impairment pursuant to SFAS No. 142. For information regarding assessing the impairment in 2002 under SFAS No. 142, please read "— New Accounting Pronouncements."

Our European operations are subject to various risks incidental to investing or operating in foreign countries. These risks include economic risks, such as fluctuations in currency exchange rates, restrictions on the repatriation of foreign earnings and/or restrictions on the conversion of local currency earnings into U.S. dollars. For example, we estimate that the impact of the devaluation of the Euro relative to the U.S. dollar during 2001 negatively affected U.S. dollar net income by approximately $2 million.

Factors Affecting the Results of Our Retail Energy Operations

General. The Texas retail electricity market fully opened to competition in January 2002. Therefore, we do not expect the earnings from our Retail Energy segment, which is operated by subsidiaries of Reliant Resources, for past years to be indicative of our future earnings and results. The level of future earnings generated by our Retail Energy segment will depend on numerous factors including:

- legislative and regulatory developments related to the newly opened retail electricity market in Texas and changes in the application of such laws and regulations;
- the effects of competition, including the extent and timing of the entry or exit of competitors in our markets and the impact of competition on retail prices and margins;
- customer attrition rates and cost associated with acquiring and retaining new customers;
- our ability to negotiate new contracts or renew contracts with customers on favorable terms;
- the timing and extent of changes in wholesale commodity prices and transmission and distribution rates;
- our ability to procure adequate electricity supply upon economic terms;
- our ability to effectively hedge commodity prices;
- our ability to pass increased supply costs on to customers in a timely manner;
- our ability to timely perform our obligations under our customer contracts;
- market liquidity for wholesale power;
- the financial condition and payment patterns of our customers;
- weather variations and other natural phenomena;
- the timely and accurate implementation of the new internal and external information technology systems and processes necessary to provide customer information and to implement customer switching in the retail electricity market in Texas which was established in late 2001;
- the costs associated with operating our internal customer service and other operating functions; and
- the timing and accuracy of ERCOT settlements, and the exchange of information between ERCOT, the T&D Utility and our Retail Energy segment's retail electric provider, which facilitates our Retail Energy business segment's billing, collection and supply management processes.

Competition in the Texas Market. Under the Texas Electric Restructuring Law, beginning in 2002, all classes of Texas customers of most investor-owned utilities, and those of any municipal utility and electric cooperative that opted to participate in the competitive marketplace, are able to choose their retail electric provider. In January 2002, Reliant Resources began to provide retail electric services to all customers of Reliant Energy HL&P who did not select another retail electric provider. Under the market framework established by the Texas Electric Restructuring Law, Reliant Resources is recognized as the affiliated retail electric provider of Reliant Energy's electric utility. The Distribution will not change this treatment, even though Reliant Resources will cease to be a subsidiary of Reliant Energy after the Distribution. As an affiliated retail electric provider, Reliant Resources is initially required to sell electricity to these Houston area residential and small commercial customers at a specified price, which is referred to in the law as the "price to beat," whereas other retail electric providers are allowed to sell electricity to these customers at any price. Reliant Resources' price to beat was set at a level resulting in an estimated average 17% reduction from December 31, 2001 rates for its residential customers and an estimated average 22% reduction from December 31, 2001 rates for its pre-existing small commercial customers. The wholesale energy supply cost component, or "fuel factor," included in its price to beat was initially set by the Texas Utility Commission at the then average forward 12 month gas price strip of approximately $3.11/MMBtu.

Reliant Resources is not permitted to offer electricity to these customers at a price other than the price to beat until January 1, 2005, unless before that date the Texas Utility Commission determines that 40% or more of the amount of electric power that was consumed in 2000 by the relevant class of customers in the Houston metropolitan area is committed to be served by retail electric providers other than Reliant Resources. In addition, as the affiliated retail electric provider, Reliant Resources is obligated to offer the price to beat to requesting residential and small commercial customers in Reliant Energy's electric utility service territory through January 1, 2007. Because Reliant Resources will not be able to compete for residential and small commercial customers on the basis of price in the Houston area, it may lose a significant number of these customers to other retail electric providers. Customers were given the opportunity to switch beginning in August 2001 through the retail pilot project. Due to system related problems which restricted the timely switching of customers during the pilot project and in early 2002, we cannot be sure of the number of customers that have attempted to switch to other retail electric providers. For additional information regarding retail market systems problems, please read "— Operational Risks." Between the beginning of the pilot project in August 2001 and February 28, 2002, Reliant Resources estimates that approximately 67,000 customers (or approximately 4% of their residential and small commercial customers) have switched to other retail electric providers. Due to the switching systems problems, the actual numbers of customers that switched or attempted to switch by this date may actually be higher.

Reliant Resources is providing commodity service to the large commercial, industrial and institutional customers previously served by Reliant Energy's electric utility who did not take action to select another retail electric provider. In addition, Reliant Resources has signed contracts to provide electricity and services to large commercial, industrial and institutional customers, both in the Houston area as well as outside of the Houston market. Reliant Resources or any other retail electric provider can provide services to these customers at any negotiated price. The market for these customers is very competitive, and any of these customers that select Reliant Resources as their provider may subsequently decide to switch to another provider at the conclusion of the term of their contract with Reliant Resources.

In most retail electric markets outside the Houston area, Reliant Resources' principal competitor may be the local incumbent utility company's retail affiliate. These retail affiliates have the advantage of long-standing relationships with their customers. In addition to competition from the incumbent utilities' affiliates, Reliant Resources may face competition from a number of other retail providers, including affiliates of other non-incumbent utilities, independent retail electric providers and, with respect to sales to large commercial and industrial customers, independent power producers acting as retail electric providers. Some of these competitors or potential competitors may be larger and better capitalized than Reliant Resources.

Generally, retail electric providers will purchase electricity from the wholesale generators at unregulated rates, sell electricity to their retail customers and pay the transmission and distribution utility a regulated tariffed rate for delivering the electricity to their customers. Retail electric providers will then bill and collect

payments from the customers. Because Reliant Resources is required to sell electricity to residential and small commercial customers in the Houston area at the price to beat, it may lose a significant number of these customers to non-affiliated retail electric providers if their cost to provide electricity to these customers is lower than the price to beat. In addition, the results of our Retail Energy operations for sales to residential and small commercial customers over the next several years in Texas will be largely dependent upon the amount of gross margin, or "headroom," available in our price to beat. Until 2004, when Reliant Resources will have the option to acquire our ownership interest in Texas Genco, Reliant Resources' results will be largely based on the ability of the Wholesale Energy segment to buy power at prices that yield acceptable gross margins at revenue levels determined by the price to beat set by the Texas Utility Commission. The available headroom in the price to beat is equal to the difference between the price to beat and the sum of the charges, fees and transmission and distribution utility rates approved by the Texas Utility Commission and the price Reliant Resources pays for power to serve its price to beat customers. The larger the amount of headroom, the more incentive new market entrants should have to provide retail electric services in that particular market. The Texas Utility Commission's regulations allow affiliated retail electric providers to adjust their price to beat fuel factor based on the percentage change in the price of natural gas. In addition, they may also request an adjustment as a result of changes in their price of purchased energy. In such a request, they may adjust the fuel factor to the extent necessary to restore the amount of headroom that existed at the time the initial price to beat fuel factor was set by the Texas Utility Commission. Affiliated retail electric providers may not request that their price to beat be adjusted more than twice a year. Reliant Resources cannot estimate with any certainty the magnitude and frequency of the adjustments they may seek, if any, and the eventual impact of such adjustments on the amount of headroom. Based on forward gas prices at the end of March 2002, Reliant Resources would be able to increase its price to beat rates by approximately 4-5%. Available headroom in the Houston market, as well as in other Texas markets where Reliant Resources intends to compete, will be affected by any changes in transmission and distribution rates that may be requested by the transmission and distribution provider in the respective service territory and in taxes, fees and other charges assessed or levied by third parties. Any changes in transmission and distribution rates must be approved by the Texas Utility Commission. The Texas Utility Commission has initiated a proceeding to determine what taxes a municipality or other local taxing authority can charge retail electric providers relating to the provision of electricity.

In Texas, our Wholesale Energy business segment and our Retail Energy business segment work together in order to determine the price, demand and supply of energy required to meet the needs of our Retail Energy business segments' customers. Reliant Resources may purchase capacity from non-affiliated parties in the state mandated auctions and from our Texas generation business in the contractually mandated auctions. Reliant Resources also enters into bilateral contracts with third parties for capacity, energy and ancillary services. Supply positions are continuously monitored and updated based on retail sales forecasts and market conditions. However, Reliant Resources does not expect to cover the entire exposure of these positions to market price volatility, and the coverage will vary over time. For a discussion of risks similar to those associated with our Retail Energy segment's hedging activities, please read "— Factors Affecting the Results of Our Wholesale Energy Operations — Price Volatility," and "— Risks Associated with Our Hedging and Risk Management Activities." In addition to the factors noted in these sections, Reliant Resources' ability to adequately hedge its retail electricity requirements is also dependent on the accurate forecast of the number of our customers in each customer class and uncertainties associated with the recently established ERCOT settlement procedures.

Obligations as a Provider of Last Resort. The Texas Electric Restructuring Law requires the Texas Utility Commission to designate certain retail electric providers as providers of last resort in areas of the state in which retail competition is in effect. A provider of last resort is required to offer a standard retail electric service package for each class of customers designated by the Texas Utility Commission at a fixed, nondiscountable rate approved by the Texas Utility Commission, and is required to provide the service package to any requesting retail customer in the territory for which it is the provider of last resort. In the event that another retail electric provider fails to serve any or all of its customers, the provider of last resort is required to offer that customer the standard retail service package for that customer class with no interruption of service to the customer. The Texas Utility Commission designated Reliant Resources' subsidiary, StarEn Power to serve as the provider of last resort for residential and small commercial customers in the western

portion of the Dallas/Fort Worth metropolitan area formally served by Texas Utilities, Inc., a subsidiary of TXU, Inc. In addition, StarEn Power has been appointed as the provider of last resort for large commercial, industrial and institutional customers in Reliant Energy's electric utility service territory. StarEn Power will serve two consecutive six month terms as the provider of last resort. The first term began on January 1, 2002. The second six-month term, beginning July 1, 2002, will include a potential adjustment to the energy component of our provider of last resort rate based on a NYMEX Henry Hub natural gas index. The terms and rates for provider of last resort service are governed by a settlement between Reliant Resources and various interested parties, which settlement was approved by the Texas Utility Commission. In this role, StarEn Power retains the rights to require customer deposits and disconnect service in accordance with Texas Utility Commission rules, and to petition the Texas Utility Commission for a price change in the event it is determined that StarEn power will experience a net financial loss over the term of its provider of last resort obligations. In the first quarter of 2002, the Texas Utility Commission initiated a proceeding to review and possibly amend both the governing rules and structure of provider of last resort service and obligations. This proceeding is in its initial stages and we cannot be sure whether the structure of provider of last resort service and obligations will change, how they will change or what effect, if any, any changes would have on the financial condition, results of operations or cash flows of StarEn Power or our Retail Energy business segment.

"Clawback" Payment to Reliant Energy. To the extent the price to beat exceeds the market price of electricity, Reliant Resources will be required to make a payment to Reliant Energy in 2004 unless the Texas Utility Commission determines that, on or prior to January 1, 2004, 40% or more of the amount of electric power that was consumed in 2000 by residential or small commercial customers (at or below one MW), as applicable, within Reliant Energy HL&P's service territory is committed to be served by retail electric providers other than Reliant Resources. If the 40% test is not met and the reconciliation and a retail payment is required, the amount of this retail payment will be equal to (a) the amount that the price to beat, less non-bypassable delivery charges, is in excess of the prevailing market price of electricity during such period per customer, but not to exceed $150 per customer, multiplied by (b) the number of residential or small commercial customers, as the case may be, that we serve on January 1, 2004 in Reliant Energy HL&P's service territory, less the number of new retail electric customers Reliant Resources serves in other areas of Texas. Amounts received from Reliant Resources with respect to the clawback payment, if any, will be included in the 2004 stranded cost true-up as a reduction of stranded costs.

Operational Risks. The price of purchased power could have an adverse effect on the costs incurred by our Retail Energy segment in acquiring power to serve the demand of its retail customers. For additional information regarding commodity price volatility, please read "— Factors Affecting the Results of Our Wholesale Energy Operations — Price Volatility."

Reliant Resources is dependent on local transmission and distribution utilities for maintenance of the infrastructure through which electricity is delivered to its retail customers. Any infrastructure failure that interrupts or impairs delivery of electricity to its customers could negatively impact the satisfaction of its customers with its service. Additionally, Reliant Resources is dependent on the local transmission and distribution utilities for the reading of its customers' energy meters. Reliant Resources is required to rely on the local utility or, in some cases, the independent transmission system operator, to provide it with its customers' information regarding energy usage, and Reliant Resources may be limited in its ability to confirm the accuracy of the information. The provision of inaccurate information or delayed provision of such information by the local utilities or system operators could have a material negative impact on our business and results of operations and cash flows.

The ERCOT ISO is the independent system operator responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to anyone needing the information. Problems in the flow of information between the ERCOT ISO, the transmission and distribution utility and the retail electric providers have resulted in delays in switching customers. While the flow of information is improving, operational problems in the new system and processes are still being worked out.

The ERCOT ISO is also responsible for handling scheduling and settlement for all electricity supply volumes in the Texas deregulated electricity market. In addition, the ERCOT ISO plays a vital role in the collection and dissemination of metering data from the transmission and distribution utilities to the retail electric providers. Reliant Resources and other retail electric providers schedule volumes based on forecasts. As part of settlement, the ERCOT ISO communicates the actual volumes delivered compared to the forecast volumes scheduled. The ERCOT ISO calculates an additional charge or credit based on the difference between the actual and forecast volumes, utilizing a market clearing price for the difference. Settlement charges also include allocated costs such as unaccounted-for energy. Currently, there is a three to four month delay in receiving the final settlement information. As a result, Reliant Resources must estimate its supply costs. Timing delays in receiving final settlement information creates supply cost estimation risk.

Fluctuations in Commodity Prices and Derivative Instruments

For information regarding our exposure to risk as a result of fluctuations in commodity prices and derivative instruments, please read "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Form 10-K.

Environmental Expenditures

We are subject to numerous environmental laws and regulations, which require us to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment. For additional information regarding environmental contingencies, please read Note 14(f) to our consolidated financial statements.

Clean Air Act Expenditures. We expect the majority of capital expenditures associated with environmental matters to be incurred by our Electric Generation and Wholesale Energy business segments in connection with emission limitations for NOx under the Clean Air Act, or to enhance operational flexibility under Clean Air Act requirements. In 2000, emission reduction requirements for NOx were finalized for our electric generating facilities in the United States. We currently estimate that up to $476 million will be required to comply with the requirements through the end of 2004, with an estimated $287 million to be incurred in 2002. The Texas regulations require additional reductions that must be completed by March 2007. Plans for the Texas units for the period 2004 through 2007 have not been finalized, but have been estimated at $88 million. We are currently litigating the economic and technical viability of the Texas post-2004 reduction requirements, but cannot predict the outcome of this litigation. In addition, the Texas Electric Restructuring Law created a program mandating air emissions reductions for some generating facilities of our Electric Generation business segment. The Texas Electric Restructuring Law provides for stranded cost recovery of costs associated with this obligation incurred before May 1, 2003. For additional information regarding the Texas Electric Restructuring Law, please read "— Regulation — State and Local Regulations — Texas — Electric Operations — The Texas Electric Restructuring Law" in Item 1 of this Form 10-K and Note 4(a) to our consolidated financial statements. For additional information regarding environmental regulation of air emissions, please read "Business — Environmental Matters — Air Emissions" in Item 1 of this Form 10-K.

Site Remediation Expenditures. From time to time we have received notices from regulatory authorities or others regarding our status as a potentially responsible party in connection with sites found to require remediation due to the presence of environmental contaminants. Based on currently available information, we believe that remediation costs will not materially affect our financial position, results of operations or cash flows. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to our estimates. For information about specific sites that are the subject of remediation claims, please read Note 14(f) to our consolidated financial statements.

Water, Mercury and Other Expenditures. As discussed under "Business — Environmental Matters — Water Issues" in Item 1 of this Form 10-K, regulatory authorities are in the process of implementing regulations and quality standards in connection with the discharge of pollutants into waterways. Once these regulations and quality standards are enacted, we will be able to determine if our operations are in compliance,

or if we will have to incur costs in order to comply with the quality standards and regulations. Until that time, however, we are not able to predict the amount of these expenditures, if any. To date, however, our expenditures associated with respect to permits, registrations and authorizations for operation of facilities under the statutes regulating the discharge of pollutants into surface water have not been material. With regard to mercury remediation and other environmental matters, such as the disposal of solid wastes, our expenditures have not been, and are not expected to be material, based on our experiences and that of others in our industries. Please read "Business — Environmental Matters — Mercury Contamination" and "— Other" in Item 1 of this Form 10-K.

Other Factors

Terrorist Attacks and Acts of War. We are currently unable to measure the ultimate impact of the terrorist attacks of September 11, 2001 on our industry and the United States economy as a whole. The uncertainty associated with the retaliatory military response of the United States and other nations and the risk of future terrorist activity may impact our results of operations and financial condition in unpredictable ways. These actions could result in adverse changes in the insurance markets and disruptions of power and fuel markets. In addition, our generation facilities or the power transmission and distribution facilities on which we rely could be directly or indirectly harmed by future terrorist activity. The occurrence or risk of occurrence of future terrorist attacks or related acts of war could also adversely affect the United States economy. A lower level of economic activity could result in a decline in energy consumption which could adversely affect our revenues, margins and limit our future growth prospects. The occurrence or risk of occurrence could also increase pressure to regulate or otherwise limit the prices charged for electricity or gas. Also, these risks could cause instability in the financial markets and adversely affect our ability to access capital.

Environmental Regulation. Our Electric Generation and Wholesale Energy business segments are subject to extensive environmental regulation by federal, state and local authorities. We are required to comply with numerous environmental laws and regulations, and to obtain numerous governmental permits, in operating our facilities. We may incur significant additional costs to comply with these requirements. If we fail to comply with these requirements, we could be subject to civil or criminal liability and fines. Existing environmental regulations could be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions. If any of these events occur, our business, operations and financial condition could be adversely affected.

We may not be able to obtain or maintain from time to time all required environmental regulatory approvals. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, the operation of our facilities could be prevented or become subject to additional costs.

We are generally responsible for all on-site liabilities associated with the environmental condition of our power generation facilities which we have acquired and developed, regardless of when the liabilities arose and whether they are known or unknown. These liabilities may be substantial.

Holding Company Organizational Structure. We are a holding company, and we conduct a significant portion of our operations through our subsidiaries. After the Restructuring and Distribution, CenterPoint Energy will be a holding company that conducts substantially all of its operations through its respective subsidiaries. CenterPoint Energy's only significant assets will be the capital stock of its subsidiaries, and its subsidiaries will generate substantially all of CenterPoint Energy's operating income and cash flow. As a result, dividends or advances from CenterPoint Energy's subsidiaries will be the principal source of funds necessary to meet its debt service obligations. In some circumstances, contractual provisions (including terms of indebtedness) or laws, as well as the financial condition or operating requirements of our respective subsidiaries, may limit our or CenterPoint Energy's ability to obtain cash from our respective subsidiaries. As of December 31, 2001, all conditions on payments to us by our subsidiaries that are contained in existing agreements were satisfied. After the Distribution, Reliant Resources will also be a holding company that conducts all of its operations through its subsidiaries and will be subject to similar structural limitations as

described above with respect to CenterPoint Energy. For information regarding payment of dividends please read Item 5 of this Form 10-K.

In addition, the ability of REMA, a Reliant Resources subsidiary that owns some of the power generation facilities in our Northeast regional portfolio, to pay dividends or make restricted payments to Reliant Resources is restricted under the terms of three lease agreements under which we lease all or an undivided interest in these generating facilities. These agreements allow our Mid-Atlantic subsidiary to pay dividends or make restricted payments only if specified conditions are satisfied, including maintaining specified fixed charge coverage ratios.

Liquidity Concerns. For a discussion of factors affecting our sources of cash and liquidity, please read "— Liquidity and Capital Resources — Future Sources and Uses of Cash."

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flows

The net cash provided by/used in operating, investing and financing activities for 1999, 2000 and 2001 is as follows (in millions):

	Year Ended December 31,		
	1999	2000	2001
Cash provided by (used in):			
Operating activities	$ 1,104	$ 1,344	$ 1,713
Investing activities	(2,870)	(3,286)	(2,085)
Financing activities	1,823	2,032	337

Cash Provided by Operating Activities

Net cash provided by operations in 2001 increased $369 million compared to 2000. This increase primarily resulted from:

- an increase in recovered fuel costs by our Electric Operations business segment;
- a decrease in net margin deposits on energy trading activities as a result of reduced commodity volatility and relative price levels of natural gas and power compared to the fourth quarter of 2000; and
- an increase in operating margins from Wholesale Energy's power generation operations.

This increase is partially offset by:

- a prepayment of a lease obligation related to REMA sale/leaseback transactions (please read Note 14(b) to our consolidated financial statements);
- an increase in restricted cash related to our REMA operations;
- an increase in deposits in a collateral account related to an equipment financing structure (please read Note 14(l) to our consolidated financial statements);
- an increase in costs related to our Retail Energy business segments' increased staffing levels and preparation for competition in the retail electric market in Texas;
- reduced cash flows from our European Energy business segment primarily resulting from a decline in electric power generation gross margins as the Dutch electric market was completely opened to wholesale competition on January 1, 2001; and
- other changes in working capital.

Net cash provided by operations in 2000 increased $240 million compared to 1999. This increase primarily resulted from:

- proceeds from the sale of an investment in marketable debt securities by REPGB;
- improved operating results of our Wholesale Energy business segment's California generating facilities;
- incremental cash flows provided by REPGB, acquired in the fourth quarter of 1999;
- cash flows from REMA, acquired in the second quarter of 2000; and
- increased sales from our Electric Operations business segment due to growth in usage and number of customers.

These increases were partially offset by increases in under-recovered fuel costs of our Electric Operations business segment and Wholesale Energy's net margin deposits on energy trading activities.

Cash Used in Investing Activities

Net cash used in investing activities decreased $1.2 billion during 2001 compared to 2000. This decrease was primarily due to no acquisitions being made in 2001 as compared to the $2.1 billion acquisition of REMA in 2000, and the funding of the remaining $982 million purchase obligation for REPGB in 2000.

These decreases were partially offset by additional capital expenditures in 2001 of $211 million primarily related to our Electric Operations business segment, proceeds of $1.0 billion received in 2000 from the REMA sale-leaseback and $642 million received in 2000 from the sale of our Latin America assets, net of investments and advances.

Net cash used in investing activities increased $416 million during 2000 compared to 1999. This increase was primarily due to:

- the funding of the remaining purchase obligation for REPGB of $982 million on March 1, 2000;
- the acquisition of REMA for $2.1 billion on May 12, 2000; and
- increased capital expenditures related to the construction of domestic power generation projects.

Proceeds of $1.0 billion from the REMA sale-leaseback in 2000, the sale of a substantial portion of our Latin America investments in 2000 and the purchase of $537 million of AOL Time Warner securities in 1999 partially offset these increases.

Cash Provided by Financing Activities

Cash flows provided by financing activities decreased $1.7 billion in 2001 compared to 2000, primarily due to a decline in short term borrowings partially offset by $1.7 billion in net proceeds from the initial public offering of Reliant Resources.

Cash flows provided by financing activities increased $209 million in 2000 compared to 1999, primarily due to an increase in short-term borrowings partially offset by a decline in proceeds from long-term debt and the sale of trust preferred securities.

Future Sources and Uses of Cash

The following table sets forth our consolidated capital requirements for 2001, and estimates of our consolidated capital requirements for 2002 through 2006 (in millions).

	2001	2002	2003	2004	2005	2006
Electric Operations (with nuclear fuel) (1)	$ 936	$ —	$ —	$ —	$ —	$ —
Electric Transmission and Distribution (1)	—	338	320	381	362	352
Electric Generation (with nuclear fuel) (1)	—	285	192	89	79	45
Natural Gas Distribution	209	219	231	231	234	231
Pipelines and Gathering	54	76	45	45	43	38
Wholesale Energy (2) (3)	658	3,579	322	147	215	146
European Energy	21	22	—	—	—	—
Retail Energy	117	40	19	18	14	16
Other Operations	58	111	80	46	73	38
Major maintenance cash outlays	88	94	87	106	86	85
Total	$2,141	$4,764	$1,296	$1,063	$1,106	$951

(1) Beginning in 2002, the Electric Operations business segment will be replaced by the Electric Transmission and Distribution business segment and the Electric Generation business segment. In December 2001, we formed Texas Genco, LP, a Texas limited partnership, as an indirect, wholly owned subsidiary (Texas Genco). It is anticipated that the majority interest in Texas Genco held by CenterPoint Energy will be purchased by Reliant Resources in early 2004 pursuant to the terms of an option that Reliant Resources holds, or will otherwise be sold to one or more other parties. The Texas generation operations referred to as our "Texas generation business" throughout this Form 10-K will be reported as the "Electric Generation" business segment beginning in 2002. Capital requirements for current generation operations of Reliant Energy HL&P are included in the Electric Generation business segment. Capital requirements for the remainder of Reliant Energy HL&P's operations are included in the Electric Transmission and Distribution business segment.

(2) Capital requirements for 2002 include $2.9 billion for the acquisition of Orion Power by Reliant Resources.

(3) We currently estimate the capital expenditures by off-balance sheet special purpose entities to be $704 million, $343 million, $163 million and $48 million in 2002, 2003, 2004 and 2005, respectively. Capital expenditures for these projects have been excluded from the table above. Please read "Future Sources and Uses — Reliant Resources (unregulated businesses)," "— Off-Balance Sheet Transactions — Construction Agency Agreements" and "— Equipment Financing Structure" below for additional information.

The following table sets forth estimates of our consolidated contractual obligations as of December 31, 2001 to make future payments for 2002 through 2006 and thereafter (in millions):

Contractual Obligations	Total	2002	2003	2004	2005	2006	2007 and thereafter
Long-term debt, including capital leases(1)	$ 6,403	$ 538	$1,226	$ 90	$ 390	$218	$3,941
Short-term borrowing, including credit facilities(1)	3,435	3,435	—	—	—	—	—
Trust preferred securities(2)	706	—	—	—	—	—	706
REMA operating lease payments(3)	1,560	136	77	84	75	64	1,124
Other operating lease payments(3)	969	66	84	94	95	95	535
Trading and marketing liabilities(4)	1,840	1,478	216	85	33	13	15
Non-trading derivative liabilities(4)	1,121	472	198	115	62	35	239
Other commodity commitments(5)	4,014	451	314	340	344	348	2,217
Other long-term obligations	300	10	10	10	10	10	250
Total contractual cash obligations	$20,348	$6,586	$2,125	$818	$1,009	$783	$9,027

(1) For a discussion of short-term and long-term debt, please read Note 10 to our consolidated financial statements.

(2) For a discussion of trust preferred securities, please read Note 11 to our consolidated financial statements.

(3) For a discussion of REMA and other operating leases, please read Note 14(b) to our consolidated financial statements.

(4) For a discussion of trading and marketing liabilities and non-trading derivative liabilities, please read Note 5 to our consolidated financial statements.

(5) For a discussion of other commodity commitments, please read Note 14(a) to our consolidated financial statements. Excluded from the table above are amounts to be acquired by Reliant Resources from Texas Genco under purchase power and electric capacity commitments of $213 million and $57 million in 2002 and 2003, respectively.

The following discussion regarding future sources and uses of cash over the next twelve months is presented separately for our regulated businesses and unregulated businesses consistent with the separate liquidity plans that our management has developed for CenterPoint Energy and Reliant Resources. We believe that our borrowing capability combined with cash flows from operations will be sufficient to meet the operational needs of our businesses for the next twelve months.

Reliant Energy (to become CenterPoint Energy Subsequent to the Restructuring)

Our liquidity and capital requirements will be affected by:

- capital expenditures;
- debt service requirements;
- the repayment of notes payable to Reliant Resources;
- the reduction in, and elimination of, programs under which we have sold customer accounts receivable;
- proceeds from the expected initial public offering of Texas Genco;
- various regulatory actions; and
- working capital requirements.

We expect capital requirements to be met with cash flows from operations, as well as proceeds from debt offerings and other borrowings. The following table sets forth our capital requirements for 2001, and estimates of our capital requirements for 2002 through 2006 (in millions):

	2001	2002	2003	2004	2005	2006
Electric Operations (with nuclear fuel)(1)	$ 936	$ —	$ —	$ —	$ —	$ —
Electric Transmission and Distribution(1)	—	338	320	381	362	352
Electric Generation (with nuclear fuel)(1)	—	285	192	89	79	45
Natural Gas Distribution	209	219	231	231	234	231
Pipelines and Gathering	54	76	45	45	43	38
Other Operations	14	36	34	15	41	5
Total	$1,213	$954	$822	$761	$759	$671

(1) Beginning in 2002, the Electric Operations business segment will be replaced by the Electric Transmission and Distribution business segment and the Electric Generation business segment. It is anticipated that the majority interest in Texas Genco held by CenterPoint Energy will be purchased by Reliant Resources in early 2004 pursuant to the terms of an option that Reliant Resources holds, or will otherwise be sold to one or more other parties. The Texas generation operations referred to as our "Texas generation business" throughout this Form 10-K will be reported as the "Electric Generation" business segment beginning in 2002. Capital requirements for current generation operations of Reliant Energy HL&P are included in the Electric Generation business segment. Capital requirements for the remainder of Reliant Energy HL&P's operations are included in the Electric Transmission and Distribution business segment.

The following table sets forth estimates of our contractual obligations to make future payments for 2002 through 2006 and thereafter (in millions):

Contractual Obligations	Total	2002	2003	2004	2005	2006	2007 and thereafter
Long-term debt, including capital leases	$ 5,511	$ 514	$687	$ 48	$378	$206	$3,678
Short-term borrowing, including credit facilities	3,138	3,138	—	—	—	—	—
Trust preferred securities	706	—	—	—	—	—	706
Other operating lease payments(1)	110	14	12	7	6	5	66
Non-trading derivative liabilities	83	73	7	2	1	—	—
Other commodity commitments(2)	1,150	199	129	133	137	141	411
Total contractual cash obligations	$10,698	$3,938	$835	$190	$522	$352	$4,861

(1) For a discussion of other operating leases, please read Note 14(b) to our consolidated financial statements.

(2) For a discussion of other commodity commitments, please read Note 14(a) to our consolidated financial statements.

Credit Facilities. As of December 31, 2001, we had credit facilities, including facilities of Houston Industries FinanceCo LP (FinanceCo) and RERC Corp., that provided for an aggregate of $5.4 billion in committed credit. As of December 31, 2001, $3.1 billion was outstanding under these facilities including $2.5 billion of commercial paper supported by the facilities, borrowings of $636 million and letters of credit of $2.5 million.

The following table summarizes amounts available under these credit facilities at December 31, 2001 and commitments expiring in 2002 (in millions):

Borrower	Type of Facility	Total Committed Credit	Unused Amount at 12/31/01	Amount of Commitments Expiring in 2002
Reliant Energy	Revolver	$ 400	$ 236	$ 400
FinanceCo	Revolvers	4,300	1,671	4,300
RERC Corp.	Revolver	350	347	—
RERC Corp.	Receivables	350	4	350
Total		$5,400	$2,258	$5,050

The RERC Corp. receivables facility was reduced from $350 million to $150 million in January 2002. Proceeds for the repayment of $196 million of advances under the facility were obtained from the liquidation of a temporary investment and the sale of commercial paper.

The revolving credit facilities contain various business and financial covenants requiring us to, among other things, maintain leverage (as defined in the credit facilities) below specified ratios. We are in compliance with the covenants under all of these credit agreements. We do not expect these covenants to materially limit our ability to borrow under these facilities. For additional discussion, please read Note 10(a) to our consolidated financial statements.

The revolving credit facilities support commercial paper programs. The maximum amount of outstanding commercial paper of an issuer is limited to the amount of the issuer's aggregate revolving credit facilities less any direct loans or letters of credit obtained under its revolvers. Due to an inability to consistently satisfy all short-term borrowing needs by issuing commercial paper, short-term borrowing needs have been met with a combination of commercial paper and bank loans. The extent to which commercial paper will be issued in lieu of bank loans will depend on market conditions and our credit ratings.

Pursuant to the terms of the existing agreements (but subject to certain conditions precedent which we anticipate will be met) the revolving credit agreements aggregating $4.3 billion of FinanceCo will terminate and CenterPoint Energy revolving credit facilities of the same amount and with the same termination dates will become effective on the date of Restructuring.

To the extent that we continue to need access to current amounts of committed credit prior to the Distribution, we expect to extend or replace the credit facilities on a timely basis. The terms of any new credit facilities are expected to be adversely affected by the leverage of Reliant Energy, the amount of bank capacity utilized by Reliant Energy, any delay in the date of Restructuring and Distribution and conditions in the bank market. These same factors are expected to make the syndication of new credit facilities more difficult in the future. Proceeds from any issuance of debt in the capital markets are expected to be used to retire a portion of our short-term debt and reduce our need for committed revolving credit facilities.

Shelf Registrations. The following table lists shelf registration statements existing at December 31, 2001 for securities expected to be sold in public offerings.

Registrant	Security	Amount(1)	Terminating on Date of Restructuring
Reliant Energy.....	Preferred Stock	$230 million	Yes
Reliant Energy.....	Debt Securities	580 million	Yes
Reliant Energy.....	Common Stock	398 million	No
REI Trust II/Reliant Energy..	Trust Preferred and related Junior Subordinated Debentures	125 million	Yes
RERC Corp.	Debt Securities	50 million	No

(1) The amount reflects the principal amount of debt securities, the aggregate liquidation value of trust preferred securities and the estimated market value of common stock based on the number of shares registered as of December 31, 2001 and the closing market price of Reliant Energy common stock on that date.

We expect to register $2.5 billion of debt securities some or all of which may be issued either by Reliant Energy prior to the Restructuring or by CenterPoint Energy after the Restructuring. Proceeds from the sale of these debt securities are expected to be used to repay short-term borrowings. The amount actually issued will depend on interest rates and other market conditions.

Debt Service Requirements. Excluding the repayments expected to be made on the transition bonds described in Note 4(a) to our consolidated financial statements, we have maturing long-term debt in 2002 aggregating $500 million. Maturing debt is expected to be refinanced with new debt. In addition, Reliant Energy has $175 million of 5.20% pollution control bonds that are expected to be remarketed in 2002 as multi-year fixed-rate debt.

Debt service requirements will be affected by the overall level of interest rates in 2002 and credit spreads applicable to the various issuers of debt in 2002. Up to $2.7 billion of long-term debt is expected to be issued or remarketed in 2002 and we expect to have large amounts of short-term floating-rate debt in 2002. At December 31, 2001, we had entered into five year forward starting interest rate swaps having an aggregate notional amount of $500 million to hedge the interest rate on an anticipated 2002 offering of five year notes. The weighted average rate on the swaps was 5.6%. At December 31, 2001, we also had entered into interest rate swaps to fix the rate on $1.8 billion of our floating rate debt. The weighted average rate on these swaps was 4.1% and the swaps expire in 2002 and 2003. While we have, in some instances, hedged our exposure to changes in interest rates by entering into interest rate swaps, the swaps leave us exposed to changes in our credit spread relative to the market indices reflected in the swaps.

Money Fund. We have a "money fund" through which Reliant Energy and participating subsidiaries can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The money fund's net funding requirements are generally met with commercial paper and/or bank loans. At December 31, 2001, Reliant Resources had $390 million invested in the money fund. Reliant Resources is expected to withdraw its investment from the money fund on or before the Distribution. Funds for repayment of the notes payable to Reliant Resources will be obtained from bank loans or the issuance of commercial paper.

Environmental Issues. We anticipate investing up to $397 million in capital and other special project expenditures between 2002 and 2006 for environmental compliance. Of this amount, we anticipate expenditures to be approximately $234 million and $132 million in 2002 and 2003, respectively. These environmental compliance expenditures are included in the capital requirements table presented above. For additional information related to environmental issues, please read Note 14(f) to our consolidated financial statements.

Initial Public Offering of Texas Genco. In 2002, approximately 20% of Texas Genco is expected to be sold in an initial public offering or distributed to holders of CenterPoint Energy common stock. The decision

whether to distribute the Texas Genco shares or to sell the shares in an initial public offering will depend on numerous factors, including market conditions. Proceeds, if any, are expected to be used to retire short-term debt.

Fuel Filing. As of December 31, 2000 and 2001, Reliant Energy HL&P was under-collected on fuel recovery by $558 million and $200 million, respectively. In two separate filings with the Texas Utility Commission in 2000, Reliant Energy HL&P received approval to implement fuel surcharges to collect the under-recovery of fuel expenses, as well as to adjust the fuel factor to compensate for significant increases in the price of natural gas. Under the Texas Electric Restructuring Law, a final settlement of these stranded costs will occur in 2004.

Reliant Energy HL&P Rate Matters. The October 3, 2001 Order established the transmission and distribution rates that became effective in January 2002. The Texas Utility Commission determined that Reliant Energy HL&P had overmitigated its stranded costs by redirecting transmission and distribution depreciation and by accelerating depreciation of generation assets as provided under the Transition Plan and Texas Electric Restructuring Law. In this final order, Reliant Energy HL&P is required to reverse the amount of redirected depreciation and accelerated depreciation taken for regulatory purposes as allowed under the Transition Plan and the Texas Electric Restructuring Law. Per the October 3, 2001 Order, our Electric Operations business segment recorded a regulatory liability to reflect the prospective refund of the accelerated depreciation. Our Electric Operations business segment began refunding excess mitigation credits with the January 2002 unbundled bills, to be refunded over a seven year period. The annual cash flow impact of the reversal of both redirected and accelerated depreciation is a decrease of approximately $225 million. Under the Texas Electric Restructuring Law, a final settlement of these stranded costs will occur in 2004. For further discussion, please read Note 4(a) to our consolidated financial statements.

In addition to the above factors, our liquidity and capital requirements could be affected by:

- a downgrade in credit ratings;
- the need to provide cash collateral in connection with trading activities;
- various regulatory actions; and
- funding of our pension plan.

Impact on Liquidity of a Downgrade in Credit Ratings. At December 31, 2001, Moody's Investors Service, Inc. (Moody's), Standard & Poor's, a division of The McGraw Hill Companies (S&P) and Fitch, Inc. (Fitch) had assigned the following credit ratings to senior debt of Reliant Energy and certain subsidiaries:

	Moody's		S&P				
Company/Instrument	Rating	Outlook	Rating	Outlook	Rating	Fitch Watch	Outlook
Reliant Energy							
Senior Secured Debt	A3	Stable(1)	BBB+	Stable(2)	A-	Negative(3)	N/A
Senior Unsecured Debt	Baa1	Stable(1)	BBB	Stable(2)	BBB+	Negative(3)	N/A
Reliant Energy FinanceCo II LP							
Senior Debt	Baa1	Stable(1)	BBB	Stable(2)	BBB	N/A	Stable(4)
RERC Corp.							
Senior Debt	Baa2	Stable(1)	BBB+	Stable(2)	BBB+	Negative(3)	N/A

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

(2) A "stable" outlook from S&P indicates that the rating is not likely to change over the intermediate to longer term.

(3) A "negative" watch from Fitch signals that the rating may be downgraded or affirmed in the near term. Fitch has indicated that the Reliant Energy senior secured debt ratings will change from A- to BBB+

upon the distribution of Reliant Resources shares and that the RERC Corp. senior debt ratings will change from BBB+ to BBB upon the distribution of Reliant Resources shares.

(4) A "stable" outlook from Fitch signals that the medium term view of the credit trend of an issuer is stable rather than positive or negative.

We cannot assure you that these ratings will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to access capital on acceptable terms.

A decline in credit ratings would increase commitment fees and borrowing costs under our existing bank credit facilities. A decline in credit ratings would also adversely affect our ability to issue commercial paper and the interest rates applicable to commercial paper. Increased direct borrowings under our bank credit facilities could also result in the payment of usage fees under the terms of these arrangements. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets.

Our revolving credit agreements are broadly syndicated committed facilities which contain "material adverse change" clauses that could impact our ability to borrow under these facilities. The "material adverse change" clauses generally relate to our ability to perform our obligations under the agreements.

The $150 million receivables facility of RERC Corp. requires the maintenance of credit ratings of at least BB from S&P and Ba2 from Moody's. Advances under the facility would need to be repaid in the event a credit rating fell below the threshold.

As previously discussed, bank facilities of FinanceCo are expected to be converted into bank facilities of CenterPoint Energy on the date of Restructuring. There is a ratings-related condition precedent to the conversion from the existing FinanceCo bank credit facilities (totaling $4.3 billion) to facilities under which CenterPoint Energy will become the obligor. The condition precedent requires that CenterPoint Energy be rated at least BBB by S&P and Baa2 by Moody's at the time of Restructuring. We believe that we could obtain a waiver of this condition, if necessary. However, if we were unable to obtain such a waiver, the facilities would remain obligations of FinanceCo until the earlier of 90 days after the date of Restructuring or the expiration of the facilities in July 2002, subject to compliance with applicable covenants.

Similar ratings-related provisions govern the transfer to CenterPoint Energy of rights and obligations under certain interest rate swap agreements entered into by Reliant Energy and Houston Industries FinanceCo LP to effect interest rate hedging. Interest rate swaps having an aggregate notional amount of $1.5 billion as of December 31, 2001 contained such provisions. These agreements are generally assumable by CenterPoint Energy without the consent of the counterparties, provided that CenterPoint Energy's rating is at least BBB- from S&P or Baa3 from Moody's. We believe that we could obtain the consent of the counterparties if necessary, but if we were unable to do so, the swaps would remain obligations of the current counterparties until their expiration. All of the swaps terminate no later than 2004.

As discussed in Note 8 to our consolidated financial statements, each ZENS note is exchangeable at the holder's option at any time for an amount of cash equal to 95% of the market value of the reference shares of AOL TW common stock attributable to each ZENS note. If our credit worthiness were to drop such that ZENS note holders felt our liquidity was adversely affected or the market for the ZENS notes was to become illiquid, some ZENS holders might decide to exchange their ZENS for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the AOL TW common stock that we own or from other sources. We own shares of AOL TW common stock equal to 100% of the "reference shares" used to calculate our obligation to the holders of the ZENS notes.

Certain of the contracts that we have entered into on behalf of Texas Genco for the sale of capacity from our Texas generation business contain requirements obligating us to put up additional security in the event that our rating or the rating of CenterPoint Energy falls below BBB- from S&P or Baa3 from Moody's. These

requirements stem from reciprocal provisions under power purchase and sale agreements with purchasers of capacity to be delivered in various monthly, 12-month or 24-month periods or "strips" until December 2003. If a downgrade below either of these levels were to occur, the purchasers would be entitled to call upon us to provide collateral to secure our obligations in a "commercially reasonable" amount within three business days of notice. Failure to provide this collateral entitles the other party to terminate the agreement and unwind all pending transactions under the agreement. Our Texas generation business is always the seller under these agreements, and its performance obligation in all cases is one of delivery, rather than payment. Accordingly, it is difficult to quantify the amount of collateral we would be required to provide as assurance for these delivery obligations. We believe that any such quantification should be predicated on our Texas generation business' ultimate exposure under these agreements. Our Texas generation business has no exposure until (1) it cannot deliver power as called for in the agreements and (2) the market cost of replacement power has increased above the contract price. In the unlikely event that our Texas generation business could not deliver any of this power as agreed, we estimate that our Texas generation business' total exposure under these contracts at December 31, 2001 was approximately $73 million.

As part of its normal business operations, our Texas generation business has also entered power purchase and sale agreements with counterparties that contain similar provisions that require a party to provide additional collateral on three business days notice when that party's rating falls below BBB- from S&P or Baa3 from Moody's. Our Texas generation business both buys and sells under these agreements, and we use them whenever possible either to locate less expensive power than our Texas generation business' marginal cost of generation or to sell power to another party who is willing to pay more than our marginal cost of generation. Our Texas generation business' purchases for 2001 under agreements with ratings triggers were approximately $23 million and its sales under those agreements were approximately $8 million. This compares to total purchases of approximately $125 million and total sales of approximately $32 million under all buy/sell agreements in 2001. We believe that this risk is mitigated because most of the purchases and sales under these arrangements take place over relatively short time periods; typically, these transactions are for one-day deliveries and rarely exceed periods of one month.

Entex Gas Resources Corp., a wholly owned subsidiary of RERC Corp., provides comprehensive natural gas sales and services to industrial and commercial customers who are primarily located within or near the territories served by our pipelines and distribution subsidiaries. In order to hedge its exposure to natural gas prices, Entex Gas Resources Corp. will have agreements with provisions standard to the industry that establish credit thresholds and then require a party to provide additional collateral on two business days' notice when that party's rating or the rating of a credit support provider for that party (RERC Corp. in this case), falls below those levels. The senior unsecured debt of RERC Corp. is currently rated BBB+ by S&P and Baa2 by Moody's. Based on these ratings, we estimate that unsecured credit limits extended to Entex Gas Resources Corp. by counterparties could aggregate $250 million; however, utilized credit capacity would typically be lower.

Regulatory Matters. Our liquidity can be impacted by regulatory actions affecting our Electric Operations and our Natural Gas Distribution business segments. For further discussion, please read Note 4 to our consolidated financial statements.

Treasury Stock Purchases. As of December 31, 2001, we were authorized under our common stock repurchase program to purchase an additional $271 million of our common stock. Our purchases under our repurchase program depend on market conditions, might not be announced in advance and may be made in open market or privately negotiated transactions. CenterPoint Energy has no current plans to engage in a significant stock buy-back program, but may seek to repurchase shares in the open market for use in various benefit and employee compensation plans, or to maintain a targeted balance of outstanding shares to the extent that original issue stock is used for such purposes.

Pension and Postretirement Benefits Funding. We make contributions to achieve adequate funding of Company sponsored pension and postretirement benefits in accordance with applicable regulations and rate orders. Based on current estimates, we expect to have funding requirements, excluding Reliant Resources, of

approximately $330 million for the period 2002-2006. These anticipated funding requirements are not reflected in the table of contractual obligations presented above.

Reliant Resources — unregulated businesses

Liquidity and capital requirements for these businesses are affected primarily by the results of operations, capital expenditures, debt service requirements and working capital needs. Reliant Resources expects to grow these businesses through the construction of new generation facilities and the acquisition of generation facilities, the expansion of their energy trading and marketing activities and the expansion of their energy retail business. Reliant Resources expects any resulting capital requirements to be met with cash flows from operations, and proceeds from debt and equity offerings, project financings, securitization of assets, other borrowings and off-balance sheet financings. Additional capital expenditures, some of which may be substantial, depend to a large extent upon the nature and extent of future project commitments which are discretionary. In the discussion below, Reliant Resources has provided several tables outlining their expected future capital requirements by category of expenditure followed by more detailed descriptions of the most significant of their currently known future capital requirements and descriptions of known uncertainties that could impact these items.

The following table sets forth Reliant Resources' consolidated capital requirements for 2001, and estimates of their consolidated capital requirements for 2002 through 2006 (in millions).

	2001	2002	2003	2004	2005	2006
Wholesale Energy(1)(2)(3)	$658	$3,579	$322	$147	$215	$146
European Energy	21	22	—	—	—	—
Retail Energy	117	40	19	18	14	16
Other Operations	44	75	46	31	32	33
Major maintenance cash outlays	88	94	87	106	86	85
Total	$928	$3,810	$474	$302	$347	$280

(1) Capital requirements for 2002 includes $2.9 billion for the acquisition of Orion Power.

(2) In connection with Reliant Resources' separation from Reliant Energy, Reliant Energy has granted Reliant Resources an option, subject to completion of the Distribution, to purchase the majority interest in Texas Genco held by CenterPoint Energy in January 2004. This option may be exercised between January 10, 2004 and January 24, 2004. The purchase of Texas Genco has been excluded from the above table. For additional information regarding this option to purchase Texas Genco, please read Note 4(b) to our consolidated financial statements.

(3) Reliant Resources currently estimates the capital expenditures by off-balance sheet special purpose entities to be $704 million, $343 million, $163 million and $48 million in 2002, 2003, 2004 and 2005, respectively. Capital expenditures for these projects have been excluded from the table above. Please read "Future Sources and Uses — Reliant Resources — unregulated businesses," "— Off-Balance Sheet Transactions — Construction Agency Agreements" and "— Equipment Financing Structure" below for additional information.

Acquisition of Orion Power. On February 19, 2002, Reliant Resources acquired all of the outstanding shares of common stock of Orion Power for $26.80 per share in cash for an aggregate purchase price of $2.9 billion. As of February 19, 2002, Orion Power's debt obligations were $2.4 billion ($2.1 billion net of cash acquired, some of which is restricted pursuant to debt covenants). Reliant Resources funded the purchase of Orion Power with a $2.9 billion credit facility (Orion Bridge Facility) and $41 million of cash on hand. Please read "— Consolidated Sources of Cash — Orion Bridge Facility" for further information.

Generating Projects. As of December 31, 2001, Reliant Resources had three generating facilities under construction. Total estimated costs of constructing these facilities are $1.1 billion, including $304 million in commitments for the purchase of combustion turbines. As of December 31, 2001, Reliant Resources had

incurred $690 million of the total projected costs of these projects, which were funded primarily from equity and debt facilities. In addition, Reliant Resources has options to purchase additional combustion turbines for a total estimated cost of $42 million, but is actively attempting to market these turbines, having determined that they are in excess of their current needs. In addition to these facilities, Reliant Resources is constructing facilities as construction agents under the construction agency agreements under synthetic leasing arrangements, which permit them to lease or buy each of these facilities at the conclusion of their construction. For more information regarding the construction agency agreements, please read "— Off Balance Sheet Transactions — Construction Agency Agreements."

Environmental Expenditures. Reliant Resources anticipates investing up to $135 million in capital and other special project expenditures between 2002 and 2006 for environmental compliance, totaling approximately $53 million, $20 million, $9 million, $29 million and $24 million in 2002, 2003, 2004, 2005 and 2006, respectively, which is included in the above table. Additionally, environmental capital expenditures for the recently acquired Orion Power assets were estimated by Orion Power to be approximately $241 million over the same time period. Reliant Resources is currently reviewing Orion Power's estimates.

The following table sets forth estimates of Reliant Resources' consolidated contractual obligations as of December 31, 2001 to make future payments for 2002 through 2006 and thereafter (in millions):

Contractual Obligations	Total	2002	2003	2004	2005	2006	2007 and thereafter
Long-term debt	$ 892	$ 24	$ 539	$ 42	$ 12	$ 12	$ 263
Short-term borrowing, including credit facilities	297	297	—	—	—	—	—
Mid-Atlantic generating assets operating lease payments	1,560	136	77	84	75	64	1,124
Other operating lease payments	859	52	72	87	89	90	469
Trading and marketing liabilities	1,840	1,478	216	85	33	13	15
Non-trading derivative liabilities	1,038	399	191	113	61	35	239
Other commodity commitments	3,134	465	242	207	207	207	1,806
Other long-term obligations	300	10	10	10	10	10	250
Total contractual cash obligations	$9,920	$2,861	$1,347	$628	$487	$431	$4,166

Long-term debt obligations as of December 31, 2001, include $829 million of borrowings under credit facilities that have been classified as long-term debt, based upon the availability of committed credit facilities and management's intention to maintain these borrowings in excess of one year.

As of December 31, 2001, Reliant Resources has issued $396 million of letters of credit, of which $345 million were issued under two credit facilities expiring in 2003 and $51 million were issued under a credit facility expiring in 2004.

Mid-Atlantic Assets Lease Obligation. In August 2000, Reliant Resources' subsidiaries entered into separate sale-leaseback transactions with each of the three owner-lessors for their respective 16.45%, 16.67% and 100% interests in the Conemaugh, Keystone and Shawville generating stations, respectively, which Reliant Resources acquired as part of the REMA acquisition. These lessees lease an interest in each facility from each owner-lessor under a facility lease agreement. The equity interests in all the subsidiaries of REMA are pledged as collateral for REMA's lease obligations. In addition, the subsidiaries have guaranteed the lease obligations. The lease documents contain restrictive covenants that restrict REMA's ability to, among other things, make dividend distributions unless REMA satisfies various conditions. The covenant restricting dividends would be suspended if the direct or indirect parent of REMA, meeting specified criteria, including having a credit rating on its long-term unsecured senior debt of at least BBB from Standard & Poor's and Baa2 from Moody's, guarantees the lease obligations. For additional discussion of these lease transactions, please read Notes 3(a) and 14(b) to our consolidated financial statements. Reliant Resources expects to make lease

payments through 2029 under these leases, with total cash payments of $1.6 billion. The lease terms expire in 2034. During 2000 and 2001, cash lease payments totalled $1 million and $259 million, respectively.

Other Operating Lease Commitments. For a discussion of other operating leases, please read Note 14(b) to our consolidated financial statements.

Other Commodity Commitments. For a discussion of other commodity commitments, please read Note 14(a) to our consolidated financial statements.

Naming Rights to Houston Sports Complex. In October 2000, Reliant Resources acquired the naming rights for the new football stadium for the Houston Texans, the National Football League's thirty-second franchise. The agreement extends for 31 years. The aggregate undiscounted cost of the naming rights under this agreement is expected to be $300 million. Starting in 2002, when the new stadium is operational, Reliant Resources will pay $10 million each year through 2032 for annual advertising under this agreement. For additional information on the naming rights agreement, please read Note 14(d) to our consolidated financial statements.

Payment to Reliant Energy. To the extent that Reliant Resources' price for providing retail electric service to residential and small commercial customers in Reliant Energy HL&P's historical service territory during 2002 and 2003, which price is mandated by the Texas Electric Restructuring Law, exceeds the market price of electricity, Reliant Resources will be required to make a payment to Reliant Energy in early 2004. Due to the nature of this possible payment, Reliant Resources currently cannot reasonably estimate this payment, and accordingly, it is excluded from the above tables.

Treasury Stock Purchases. On December 6, 2001, the Reliant Resources' board of directors authorized the purchase of up to 10 million additional shares of common stock through June 2003. Purchases will be made on a discretionary basis in the open market or otherwise at times and in amounts as determined by management subject to market conditions, legal requirements and other factors. Since the date of such authorization through March 28, 2002, Reliant Resources has not purchased any of these shares of their common stock under this program.

In addition to the capital requirements discussed above, the following items, among others, could impact future capital requirements for Reliant Resources.

Downgrade in Credit Rating. In accordance with industry practice, Reliant Resources has entered into commercial contracts or issued guarantees related to their trading, marketing and risk management operations that require them to maintain an investment grade credit rating. If one or more of their credit ratings decline below investment grade, Reliant Resources may be obligated to provide additional or other credit support to the guaranteed parties in the form of a pledge of cash collateral, a letter of credit or other similar credit support.

Counterparty Credit Risk. Reliant Resources is exposed to the risk that counterparties who owe them money or physical commodities, such as energy or gas, as a result of market transactions fail to perform their obligations. Should the counterparties to these arrangements fail to perform, Reliant Resources might incur losses if they are forced to acquire alternative hedging arrangements or replace the underlying commitment at then-current market prices. In addition, Reliant Resources might incur additional losses to the extent of amounts, if any, already paid to the defaulting counterparties.

Consolidated Sources of Cash

Reliant Resources believes that their current level of cash and borrowing capability, along with their future anticipated cash flows from operations and assuming successful refinancings of credit facilities as they mature, will be sufficient to meet the existing operational needs of their business for the next 12 months. If cash generated from operations is insufficient to satisfy their liquidity requirements, Reliant Resources may seek to sell either equity or debt securities or obtain additional credit facilities or long-term financings from financial institutions. In the discussion below, Reliant Resources has provided a description of the significant

factors that could impact their cash flows from operations, their currently available liquidity sources, currently contemplated future liquidity sources and known uncertainties that could impact these sources.

The following items will affect Reliant Resources' future cash flows from operations:

Reliant Resources Restricted Cash. Covenants under the Mid-Atlantic assets lease, discussed above, restrict REMA's ability to make dividend distributions. The restricted cash is available for REMA's working capital needs and for it to make future lease payments. As of December 31, 2001, REMA had $167 million of restricted cash. Reliant Resources currently anticipates that REMA will be able to satisfy the conditions necessary to distribute these restricted funds in 2002. In addition, the terms of two of their subsidiaries' indebtedness restrict the subsidiaries' ability to pay dividends or make restricted payments to Reliant Resources in some circumstances. Specifically, their subsidiary which holds an electric power generation facility in Channelview, Texas (Channelview) and their subsidiary which holds an equity investment in the entity owning and operating an electric power generation facility in Nevada (El Dorado) are each party to credit agreements used to finance construction of these generating plants. Both the Channelview credit agreement and the El Dorado credit agreement allow the respective subsidiary to pay dividends or make restricted payments only if specified conditions are satisfied, including maintaining specified debt service coverage ratios and debt service reserve account balances. In both cases, the amount of the dividends or restricted payments that may be paid if the conditions are met is limited to a specified level and may be paid only from a particular account.

Orion Power Restricted Cash. Substantially all of Orion Power's operations are conducted by its subsidiaries. The terms of some of its subsidiaries' indebtedness restrict the subsidiaries' ability to pay dividends to Orion Power or Reliant Resources. Restricted funds are available for such subsidiaries to make debt service payments and to meet their working capital needs. In addition, covenants under some indebtedness of Orion Power restrict its ability to pay dividends to Reliant Resources unless Orion Power meets certain conditions, including the ability to incur additional indebtedness without violating the required fixed charge coverage ratio of 2.0 to 1.0. A credit facility of Orion Power also restricts its ability to pay dividends to Reliant Resources unless the restrictions contained in certain of its subsidiaries' credit agreements have terminated and no restrictions remain under its credit agreements.

California Trade Receivables. As of December 31, 2001, Reliant Resources was owed $302 million by Cal ISO, the California Power Exchange (Cal PX) and the California Department of Water Resources (CDWR) and California Energy Resource Scheduling for energy sales in the California wholesale market, during the fourth quarter of 2000 through December 31, 2001 and has recorded an allowance against such receivables of $68 million. From January 1, 2002 through March 26, 2002, Reliant Resources has collected $45 million of these receivable balances. For additional information regarding uncertainties in the California wholesale market, please read Notes 14(f) and 14(g) to our consolidated financial statements.

Other Items. For other items that may affect our future cash flows from operations, please read "— Certain Factors Affecting Our Future Earnings" related to the Reliant Resources business segments.

The following discussion summarizes Reliant Resources' currently available liquidity sources and material factors that could impact that availability.

Credit Facilities. The following table provides a summary of the amounts owed and amounts available under Reliant Resources' various credit facilities (in millions).

	Total Committed Credit	Drawn Amount	Letters of Credit	Unused Amount	Expiring by December 31, 2002(1)
Reliant Resources, as of December 31, 2001	$5,563	$1,078	$396	$4,089	$1,114
Orion Power, as of February 19, 2002.....	2,028	1,827	95	106	1,736
Total.....					$2,850

(1) Excludes $383 million of facilities expiring in November 2002 as borrowings under such facilities are convertible into a long-term loan.

As of February 19, 2002, Reliant Resources has $2.9 billion of credit facilities which will expire in 2002. To the extent that they continue to need access to this amount of committed credit, Reliant Resources expects to extend or replace these facilities. The current credit environment currently impacting their industry may require their future facilities to include terms that are more restrictive or burdensome or at higher borrowing rates than those of their current facilities.

Reliant Resources Credit Facilities Covenants. As of December 31, 2001, Reliant Resources, including certain of their subsidiaries, had committed credit facilities of $5.6 billion. Of these facilities, $5.0 billion contain various business and financial covenants requiring them to, among other things, maintain a ratio of net balance sheet debt to the sum of net balance sheet debt, subordinated affiliate balance sheet debt and stockholders' equity not to exceed 0.60 to 1.00. These covenants are not anticipated to materially restrict Reliant Resources from borrowing funds or obtaining letters of credit under these facilities. The remaining credit facilities of $0.6 billion, which were held by certain of their domestic power generation subsidiaries, contain various business and financial covenants that are typical for limited or non-recourse project financings. Such covenants include restrictions on dividends and capital expenditures, as well as requirements regarding insurance, approval of operating budgets and commercial contracts. These covenants are not anticipated to materially restrict Reliant Resources from borrowing funds or obtaining letters of credit under their credit facilities. None of the above committed bank credit facilities have any defaults or prepayments triggered by changes in credit ratings, or are in any way linked to the price of Reliant Resources' common stock or any other traded instrument.

For additional information regarding the terms and related interest rates of these credit facilities, please read Note 10 of our consolidated financial statements.

Orion Power Credit Facilities. The credit facilities of Orion Power and its subsidiaries contain various business and financial covenants that are typical for limited or non-recourse project financings. Such covenants include restrictions on dividends and capital expenditures, as well as requirements regarding insurance, approval of operating budgets and commercial contracts. These include covenants that require two of Orion Power's significant subsidiaries which have credit facilities with outstanding borrowings of $1 6 billion as of December 31, 2001, to, among other things, maintain a debt service coverage ratio of at least 1.5 to 1.0, and for Orion Power, which has a $75 million credit facility, to, among other things, maintain a debt service coverage ratio of at least 1.4 to 1.0. One of the subsidiaries may not be able to meet this debt service coverage ratio for the quarter ended June 30, 2002, and Orion Power did not meet the debt service coverage ratio for the quarter ended March 31, 2002. In the event that Orion Power is unable to meet this financial covenant for a second consecutive fiscal quarter, it would constitute a default under its credit facility. Reliant Resources currently intends to arrange for the repayment, refinancing or amendment of these facilities prior to June 30, 2002. If these facilities are not repaid, refinanced or amended prior to that date, and if a waiver is required under either or both of these credit facilities, Reliant Resources believes that they will be able to obtain such a waiver on or prior to June 30, 2002. Reliant Resources currently has no assurance that they will be able to obtain such a waiver or amendment from the respective lender groups if required under either or both of these credit facilities.

Orion Bridge Facility. In November 2001, Reliant Resources entered into a $2.2 billion term loan facility to be utilized for the acquisition of Orion Power. In January 2002, the facility was increased to $2.9 billion. On February 19, 2002, in connection with the Orion Power acquisition Reliant Resources borrowed $2.9 billion under the Orion Bridge Facility, which is required to be repaid on or before February 19, 2003.

Potential Future Liquidity Sources. Reliant Resources is currently considering pursuing the following sources of cash to meet their future capital requirements.

Commercial Paper Program. Reliant Resources plans to commence a commercial paper program in 2002, which will be supported by their existing credit facilities. Although they have not yet determined the size

of such program, Reliant Resources does not expect that it would exceed $300 million initially, due to market conditions and their current credit ratings. To the extent that they are not successful in placing commercial paper consistently, Reliant Resources will borrow directly under their existing credit facilities.

Debt Securities in the Capital Markets. As part of refinancing the Orion Bridge Facility, Reliant Resources currently expects that they will issue various fixed and floating rate debt securities in 2002 having maturities up to ten years or greater depending upon market conditions. Reliant Resources expects to offer debt securities in the amount of $2.5 to $3.0 billion, depending on market conditions. Their ability to complete such debt offerings in the capital markets will depend on their future performance and prevailing market conditions. This Form 10-K does not constitute an offer to sell or the solicitation of an offer to buy debt securities of Reliant Resources or their subsidiaries.

Settlement of Indemnification of REPGB Stranded Costs. In December 2001, REPGB and its former shareholders entered into a settlement agreement resolving the former shareholders' stranded cost indemnity obligations under the purchase agreement of REPGB. Under the settlement agreement, the former shareholders paid to REPGB NLG 500 million ($202 million based on an exchange rate of 2.48 NLG per U.S. dollar as of December 31, 2001) in January and February 2002. In addition, under the settlement agreement, the former shareholders waived all rights under the original indemnification agreement to claim distributions from NEA, a 22.5% owned equity investment. Reliant Resources estimates that there will be future distributions from 2002 through 2005 from NEA to REPGB totaling approximately $299 million. For additional information regarding the settlement agreement, Reliant Resources' investment in NEA and indemnification of district heat contract obligations, please read Note 14(h) to our consolidated financial statements.

Factors Affecting Our Sources of Cash and Liquidity. As a result of several recent events, including the United States economic recession, the price decline of the common stock of participants in Reliant Resources' industry sector and the downgrading of the credit ratings of several of Reliant Resources' significant competitors, the availability and cost of capital for their business and the businesses of their competitors have been adversely affected. Any future acquisition or development projects will likely require Reliant Resources to access substantial amounts of capital from outside sources on acceptable terms. Reliant Resources may also need external financing to fund capital expenditures, including capital expenditures necessary to comply with air emission regulations or other regulatory requirements. If Reliant Resources is are unable to obtain outside financing to meet their future capital requirements on terms that are acceptable to them, their financial condition and future results of operations could be materially adversely affected. In order to meet their future capital requirements, Reliant Resources may increase the proportion of debt in their overall capital structure. Increases in their debt levels may adversely affect their credit ratings thereby increasing the cost of their debt. In addition, the capital constraints currently impacting their industry may require Reliant Resources' future indebtedness to include terms and/or pricing that are more restrictive or burdensome than those of their current indebtedness. This may negatively impact their ability to operate their business, or severely restrict or prohibit distributions from their subsidiaries.

Reliant Resources' ability to arrange financing, including refinancing, and their cost of capital are dependent on the following factors:

- general economic and capital market conditions;
- maintenance of acceptable credit ratings;
- credit availability from banks and other financial institutions;
- investor confidence in Reliant Resources, their competitors and peer companies and their wholesale power markets;
- market expectations regarding their future earnings and probable cash flows;
- market perceptions of Reliant Resources' ability to access capital markets on reasonable terms;
- the success of current power generation projects;
- the perceived quality of new power generation projects; and
- provisions of relevant tax and securities laws.

Credit Ratings. Credit ratings for Reliant Resources' senior unsecured debt are as follows:

Date Assigned	Rating Agency	Rating	Outlook
March 22, 2002	Moody's	Baa3	Stable
February 14, 2002	Fitch(1)	BBB	Negative
March 21, 2002	Standard & Poor's	BBB	Stable

(1) Fitch assigned a negative rating outlook to reflect its analysis of Reliant Resources' plan for financing and integrating the acquisition of Orion Power.

Reliant Resources cannot assure you that these ratings will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. Reliant Resources notes that these credit ratings are not recommendations to buy, sell or hold Reliant Resources' securities and may be revised or withdrawn at any time by a rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of their credit ratings could have a material adverse impact on Reliant Resources' ability to access capital on acceptable terms. Reliant Resources has commercial contracts and/or guarantees related to their trading, marketing and risk management and hedging operations that require them to maintain an investment grade credit rating. If their credit rating declines below investment grade, Reliant Resources estimates that they could be obligated to provide significant credit support to the counterparties in the form of a pledge of cash collateral, a letter of credit or other similar credit support.

Furthermore, if their credit ratings decline below an investment grade credit rating, Reliant Resources' trading partners may refuse to trade with them or trade only on terms less favorable to them. As of December 31, 2001, Reliant Resources had $214 million of margin deposits on energy trading and hedging activities posted as collateral with counterparties. As of December 31, 2001, Reliant Resources had $1.5 billion available under their credit facilities to satisfy future commodity obligations.

Off-Balance Sheet Transactions

Construction Agency Agreements. In 2001, Reliant Resources, through several of their subsidiaries, entered into operative documents with special purpose entities to facilitate the development, construction, financing and leasing of several power generation projects. The special purpose entities are not consolidated by Reliant Resources. The special purpose entities have an aggregate financing commitment from equity and debt participants (Investors) of $2.5 billion of which the last $1.1 billion is currently available only if the cash is collateralized. The availability of the commitment is subject to satisfaction of various conditions, including the obligation to provide cash collateral for the loans and letters of credit outstanding on November 27, 2004. Reliant Resources, through several of their subsidiaries, acts as construction agent for the special purpose entities and is responsible for completing construction of these projects by December 31, 2004, but Reliant Resources has generally limited their risk during construction to an amount not in excess of 89.9% of costs incurred to date, except in certain events. Upon completion of an individual project and exercise of the lease option, their subsidiaries will be required to make lease payments in an amount sufficient to provide a return to the Investors. If Reliant Resources does not exercise their option to lease any project upon its completion, they must purchase the project or remarket the project on behalf of the special purpose entities. Reliant Resources' ability to exercise the lease option is subject to certain conditions. Reliant Resources must guarantee that the Investors will receive an amount at least equal to 89.9% of their investment in the case of a remarketing sale at the end of construction. At the end of an individual project's initial operating lease term (approximately five years from construction completion), Reliant Resources' subsidiary lessees have the option to extend the lease with the approval of Investors, purchase the project at a fixed amount equal to the original construction cost, or act as a remarketing agent and sell the project to an independent third party. If the lessees elect the remarketing option, they may be required to make a payment of an amount not to exceed 85% of the project cost, if the proceeds from remarketing are not sufficient to repay the Investors. Reliant Resources has guaranteed the performance and payment of their subsidiaries' obligations during the construction periods and, if the lease option is exercised, each lessee's obligations during the lease period. At anytime during the

construction period or during the lease, Reliant Resources may purchase a facility by paying an amount approximately equal to the outstanding balance plus costs. As of December 31, 2001, the special purpose entities had property, plant and equipment of $428 million and net other assets of $52 million, which were primarily restricted cash and debt obligations of $465 million. As of December 31, 2001, the special purpose entities had equity from unaffiliated third parties of $15 million. Reliant Resources currently estimates the aggregate cost of the three generating facilities that are currently under construction by the special purpose entities to be approximately $1.8 billion.

Equipment Financing Structure. Reliant Resources, through their subsidiary, REPG, has entered into an agreement with a bank whereby the bank, as owner, entered or will enter into contracts for the purchase and construction of power generation equipment and REPG, or its subagent, acts as the bank's agent in connection with administering the contracts for such equipment. Under the agreement, the bank has agreed to provide up to a maximum aggregate amount of $650 million. REPG and its subagents must cash collateralize their obligation to administer the contracts. This cash collateral is approximately equivalent to the total payments by the bank for the equipment, interest and other fees. As of December 31, 2001, the bank had assumed contracts for the purchase of eleven turbines, two heat recovery steam generators and one air-cooled condenser with an aggregate cost of $398 million. REPG, or its designee, has the option at any time to purchase or, at equipment completion, subject to certain conditions, including the agreement of the bank to extend financing, to lease equipment, or to assist in the remarketing of the equipment under terms specified in the agreement. All costs, including the purchase commitment on the turbines, are the responsibility of the bank. The cash collateral is deposited by REPG or an affiliate into a collateral account with the bank and earns interest at the London inter-bank offered rate (LIBOR) less 0.15%. Under certain circumstances, the collateral deposit or a portion of it will be returned to REPG or its designee. Otherwise it will be retained by the bank. At December 31, 2001, REPG and its subsidiary had deposited $230 million into the collateral account. The bank's payments for equipment under the contracts totaled $227 million as of December 31, 2001. In January 2002, the bank sold to the parties to the construction agency agreements discussed above, equipment contracts with a total contractual obligation of $258 million under which payments and interest during construction totaled $142 million. Accordingly, $142 million of our collateral deposits were returned to Reliant Resources. As of December 31, 2001, there were equipment contracts with a total contractual obligation of $140 million under which payments during construction totaled $83 million. Currently this equipment is not designated for current planned power generation construction projects. Therefore, Reliant Resources anticipates that it will either purchase the equipment, assist in the remarketing of the equipment or negotiate to cancel the related contracts.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the portrayal of our financial condition and results of operations and requires management to make difficult, subjective or complex judgments. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be perceived with certainty. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes.

We believe the following are the most significant estimates used in the preparation of our consolidated financial statements.

Accounting for Rate Regulation

SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Our rate-

regulated businesses follow the accounting and reporting requirements of SFAS No. 71. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. The total amounts of regulatory assets and liabilities reflected in the Consolidated Balance Sheets are $1.9 billion and $237 million at December 31, 2000, and $3.3 billion and $1.4 billion at December 31, 2001, respectively.

Application of SFAS No. 71 to the generation portion of our business was discontinued as of June 30, 1999. Only the electric transmission and distribution business, the natural gas distribution companies and one of our interstate pipelines are subject to SFAS No. 71 after January 1, 2002. We have recorded regulatory assets and liabilities related to stranded costs associated with our electric generation operations. Under the Texas Electric Restructuring Law, a final settlement of these stranded costs will occur in 2004. In the event that regulation significantly changes the probability for us to recover our costs in the future, a write-down of all or a portion of our existing regulatory assets and liabilities could result.

Impairment of Long-Lived Assets and Assets Held for Sale

Long-lived assets, which include property, plant and equipment, goodwill and other intangibles and equity investments comprise a significant amount of our total assets. We make judgments and estimates in conjunction with the carrying value of these assets, including amounts to be capitalized, depreciation and amortization methods and useful lives. Additionally, the carrying values of these assets are periodically reviewed for impairment or whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. An impairment loss is recorded in the period in which it is determined that the carrying amount is not recoverable. This requires us to make long-term forecasts of future revenues and costs related to the assets subject to review. These forecasts require assumptions about demand for our products and services, future market conditions and regulatory developments. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period.

During December 2001, we evaluated our European Energy business segment's long-lived assets and goodwill for impairment. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. As of December 31, 2001, pursuant to SFAS No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," (SFAS No. 121) no impairment had been indicated.

During the fourth quarter of 2001, the Distribution of Reliant Resources common stock to our shareholders was deemed to be a probable event. As Reliant Resources has an option to purchase our majority interest in Texas Genco in 2004, we were required to evaluate these assets for potential impairment in accordance with SFAS No. 121, due to an expected decrease in the number of years we expect to hold and operate these assets. As of December 31, 2001, no impairment had been indicated. We anticipate that future events, such as the expected public offering of Texas Genco shares (please read Note 4(b)), or change in the estimated holding period of the Texas generation assets, will require us to re-evaluate our Texas generation assets for impairment between now and 2004. If an impairment is indicated, it could be material and will not be fully recoverable through the 2004 true-up proceeding calculations (please read Notes 2(e) and 4(a) to our consolidated financial statements).

Assets held for sale are evaluated based on estimated net realizable value in accordance with Emerging Issues Task Force Issue No. 90-6. During December 2001, we concluded that there was an impairment related to our remaining Latin America assets held for sale. This evaluation resulted in an after-tax impairment charge in 2001 of $43 million, representing the excess of book value over estimated net realizable value. As of December 31, 2001, we had $8 million of Latin America net assets held for sale recorded in the Consolidated Balance Sheets. The charge was included as a component of operating income with respect to consolidated subsidiaries and other income with respect to equity investments in unconsolidated subsidiaries. The impairment was primarily related to the recent adverse economic developments in Argentina. We do not intend to invest additional resources in these operations. For additional information about our Latin America assets, please read Note 19 to our consolidated financial statements.

Unbilled Energy Revenues

Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meters which are read on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled electric revenue is estimated each month based on daily generation volumes, line losses and applicable customer rates based on analyses reflecting significant historical trends and experience. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. Accrued unbilled revenues recorded in the Consolidated Balance Sheet as of December 31, 2000 were $39 million related to our Electric Operations business segment, $3 million related to our Retail Energy business segment and $551 million related to our Natural Gas Distribution business segment. Accrued unbilled revenues recorded in the Consolidated Balance Sheet as of December 31, 2001 were $33 million related to our Electric Operations business segment, $5 million related to our Retail Energy business segment and $188 million related to our Natural Gas Distribution business segment.

Accounting for Derivatives and Hedging Instruments

SFAS No. 133 established accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires an entity to recognize the fair value of derivative instruments held as assets or liabilities on the balance sheet. In accordance with SFAS No. 133, the effective portion of the change in the fair value of a derivative instrument designated as a cash flow hedge is reported in other comprehensive income, net of tax. Amounts in accumulated other comprehensive income are ultimately recognized in earnings when the related hedged forecasted transaction occurs. The change in the fair value of the ineffective portion of the derivative instrument designated as a cash flow hedge is recorded in earnings. Derivative instruments that have not been designated as hedges are adjusted to fair value through earnings.

We utilize derivative instruments such as futures, physical forward contracts, swaps and options to mitigate the impact of changes in electricity, natural gas and fuel prices on our operating results and cash flows. We utilize cross-currency swaps, forward contracts and options to hedge our net investments in and cash flows of our foreign subsidiaries, interest rate swaps to mitigate the impact of changes in interest rates and other financial instruments to manage various other market risks.

The determination of fair values of trading and marketing assets and liabilities for our energy trading, marketing and price risk management operations and non-trading derivative assets and liabilities, including stranded cost obligations related to our European Energy operations, are based on estimates. For further discussion, please read "—Trading and Marketing Operations", "Quantitative and Qualitative Disclosure About Market Risk" in Item 7A of this Form 10-K and Note 5 to our consolidated financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 "Business Combinations" (SFAS No. 141) and SFAS No. 142. SFAS No. 141 requires business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting and broadens the criteria for recording intangible assets separate from goodwill. Recorded goodwill and intangibles will be evaluated against these new criteria and may result in certain intangibles being transferred to goodwill, or alternatively, amounts initially recorded as goodwill may be separately identified and recognized apart from goodwill. SFAS No. 142 provides for a nonamortization approach, whereby goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and written down and charged to results of operations only in the periods in which the recorded value of goodwill and certain intangibles with indefinite lives is more than its fair value. We adopted the provisions of each statement which apply to goodwill and intangible assets acquired prior to June 30, 2001 on January 1, 2002. The adoption of SFAS No. 141 did not have a material impact on our historical results of operations or financial position.

On January 1, 2002, we discontinued amortizing goodwill into the results of operations pursuant to SFAS No. 142. We recognized $81 million of goodwill amortization expense in our Statements of Consolidated Income during 2001, excluding a $19 million write-off of a Communications business goodwill balance which was recorded as goodwill amortization expense (please read Note 20 to our consolidated financial statements). We are in the process of determining further effects of adoption of SFAS No. 142 on our consolidated financial statements, including the review of goodwill and certain intangible assets for impairment. We have not completed our review pursuant to SFAS No. 142. However, based on our preliminary review, we believe an impairment of our European Energy business segment goodwill is reasonably possible. As of December 31, 2001, net goodwill associated with our European Energy business segment is $632 million. We have not completed our preliminary review of our other business segments with net goodwill totaling $2.0 billion. We anticipate finalizing our review of goodwill and certain intangible assets during 2002.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires the fair value of a liability for an asset retirement legal obligation to be recognized in the period in which it is incurred. When the liability is initially recorded, associated costs are capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. SFAS No. 143 requires entities to record a cumulative effect of change in accounting principle in the income statement in the period of adoption. We plan to adopt SFAS No. 143 on January 1, 2003 and are in the process of determining the effect of adoption on our consolidated financial statements. For certain operations subject to cost of service rate regulation, we are permitted to include annual charges for cost of removal and nuclear decommissioning costs in the revenues we charge customers.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). SFAS No. 144 provides new guidance on the recognition of impairment losses on long-lived assets to be held and used or to be disposed of and also broadens the definition of what constitutes a discontinued operation and how the results of a discontinued operation are to be measured and presented. SFAS No. 144 supercedes SFAS No. 121 and APB Opinion No. 30, while retaining many of the requirements of these two statements. Under SFAS No. 144, assets held for sale that are a component of an entity will be included in discontinued operations if the operations and cash flows will be or have been eliminated from the ongoing operations of the entity and the entity will not have any significant continuing involvement in the operations prospectively. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001, with early adoption encouraged. SFAS No. 144 is not expected to materially change the methods we use to measure impairment losses on long-lived assets, but may result in additional future dispositions being reported as discontinued operations than was previously permitted. We adopted SFAS No. 144 on January 1, 2002.

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

Market Risk

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

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

- Currency rate risk results from exposures to changes in the value of foreign currencies relative to our reporting currency, the U.S. dollar, and exposures to changes in currency rates in transactions executed in currencies other than a business segment's reporting currency.

- Equity price risk results from exposures to changes in prices of individual equity securities.

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

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

Our trading operations enter into derivative instrument transactions as a means of risk management, optimization of our current power generation asset position, and to take a market position. Derivative instrument transactions are entered into in our non-trading operations to manage and hedge certain exposures, such as exposure to changes in electricity and fuel prices, exposure to purchase and sale commitments of natural gas, exposure to interest rate risk on our floating-rate borrowings and foreign currency exposures related to our foreign investments. We believe that the associated market risk of these instruments can best be understood relative to the underlying assets or risk being hedged and our trading strategy.

Trading Market Risk

Trading and marketing operations often involve market risk associated with managing energy commodities and establishing open positions in the energy markets, primarily on a short-term basis, through derivative instruments (Trading Energy Derivatives). Our trading and marketing businesses depend on price movements and volatility levels to create business opportunities, but these businesses must control risk within authorized limits.

We assess the risk of Trading Energy Derivatives using a value-at-risk (VAR) method, in order to maintain our total exposure within authorized limits. VAR is the potential loss in value of trading positions due to adverse market movements over a defined time period within a specified confidence level. We utilize the variance/covariance model of VAR, which relies on statistical relationships to describe how changes in different markets can affect a portfolio of instruments with different characteristics and market exposures.

For the VAR numbers reported below, a one-day holding period and a 95% confidence level were used, except for our European trading operations which uses a two-day to five-day holding period. This means that if VAR is calculated at $10 million, we may state that there is a one in 20 chance that if prices move against our consolidated diversified positions, our pre-tax loss in liquidating or offsetting with hedges our portfolio in a one-day period would exceed $10 million.

The VAR methodology employs a seasonally adjusted volatility-based approach with the following critical parameters: forward prices and volatility estimates, appropriate market-oriented holding periods and seasonally adjusted correlation estimates. We use the delta approximation method for reporting option positions. The instruments being evaluated could have features that may trigger a potential loss in excess of calculated amounts if changes in commodity prices exceed the confidence level of the model used. An inherent limitation of VAR is that past changes in market risk may not produce accurate predictions of future market risk. Moreover, VAR calculated for a one-day holding period does not fully capture the market risk of positions that cannot be liquidated or offset with hedges within one day. We cannot assure you that market volatility, failure of counterparties to meet their contractual obligations, future transactions or a failure of risk controls will not lead to significant losses from our trading, marketing and risk management activities.

While we believe that our assumptions and approximations are reasonable for calculating VAR, there is no uniform industry methodology for estimating VAR, and different assumptions and/or approximations could produce materially different VAR estimates.

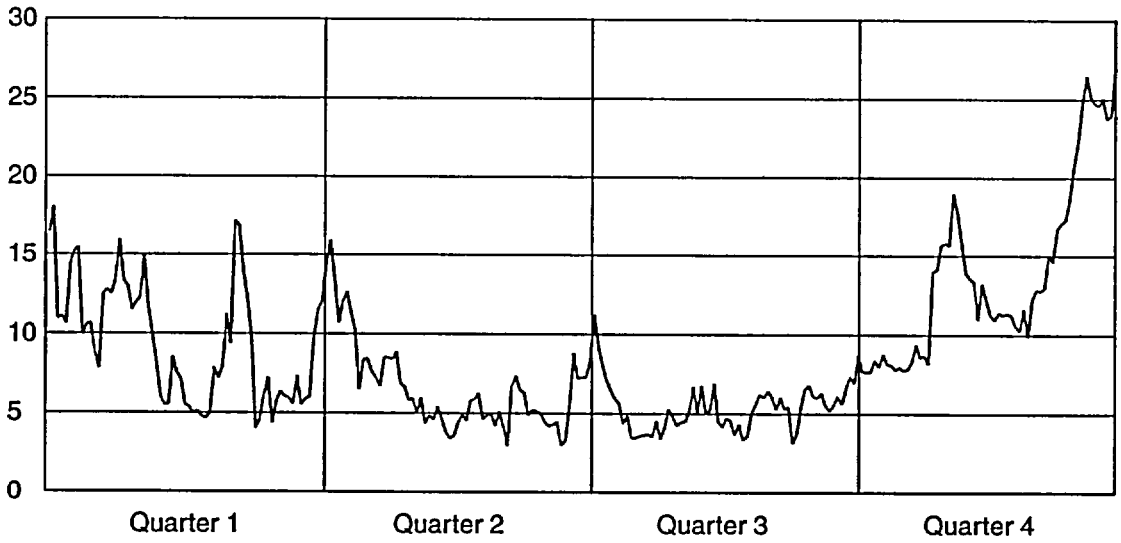
Our VAR limits are set by our board of directors, as further discussed below. Violations in overall VAR limits are required to be reported to the Audit Committee of our board of directors pursuant to our corporate-wide risk limit parameters. For further discussion on our risk management framework, please read "— Risk Management Structure" below.

The following presents the daily VAR for substantially all of our Trading Energy Derivative positions (in millions).

	2000	2001
As of December 31,	$15	$27
Year Ended December 31:		
Average	6	9
High	36	27
Low	1	3

The following chart presents the daily VAR for substantially all of our Trading Energy Derivatives during 2001 (in millions).

Combined Domestic and European VAR
For the Year Ended December 31, 2001



During the beginning of 2001, the high VAR levels were due to high natural gas and power prices and volatility levels, which continued from late 2000. VAR exposure was lower in the second and third quarters of 2001 due to the significant decline in natural gas and power prices and volatility levels. During the fourth quarter of 2001, VAR levels increased due to increased power marketing activities in ERCOT related to our Retail Energy business segment.

Non-trading Market Risk

Commodity Price Risk

Commodity price risk is an inherent component of our electric power generation businesses because the profitability of our generation assets depends significantly on commodity prices sufficient to create gross margin. During 2001, the majority of our non-trading commodity price risk was related to our electric power generation businesses. Prior to the energy delivery period, we attempt, in part to hedge the economics of our electric power facilities by selling power and purchasing equivalent fuel. Some power capacity is held in reserve and sold in the spot market. Non-trading derivative instruments (Non-trading Energy Derivatives) are used to mitigate exposure to variability in future cash flows from probable, anticipated future transactions attributable to a commodity risk. In this way, more certainty is provided as to the financial contribution associated with the operation of these assets. Beginning in 2002, our commodity price risk exposures related to our Retail Energy operations increased as we began to provide retail electric services to all customers of the T&D Utility who did not select another retail electric provider. For a discussion of risk factors affecting our Retail Energy operations, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Our Future Earnings — Factors Affecting the Results of Our Retail Energy Operations" in Item 7 of this Form 10-K.

To reduce our commodity price risk from market fluctuations in the revenues derived from the sale of natural gas and related transportation, we enter into futures transactions, forward contracts, swaps and options in order to hedge some expected purchases of natural gas and sales of natural gas (a portion of which are firm commitments at the inception of the hedge). Non-trading Energy Derivatives are also utilized to fix the price of compressor fuel or other future operational gas requirements and to protect natural gas distribution earnings against unseasonably warm weather during peak gas heating months, although usage to date for this purpose has not been material.

Derivative instruments, which we use as economic hedges, create exposure to commodity prices, which we use to offset the commodity exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our Non-trading Energy Derivatives using a sensitivity analysis. The sensitivity analysis performed on our Non-trading Energy Derivatives measures the potential loss in earnings based on a hypothetical 10% movement in energy prices. An increase of 10% in the market prices of energy commodities from their December 31, 2001 levels would have decreased the fair value of our Non-trading Energy Derivatives by $38 million, excluding non-trading derivatives liabilities associated with our European Energy business segment's stranded cost import contracts.

The above analysis of the Non-trading Energy Derivatives utilized for hedging purposes does not include the favorable impact that the same hypothetical price movement would have on our physical purchases and sales of natural gas and electric power to which the hedges relate. Furthermore, the Non-trading Energy Derivative portfolio, excluding the stranded cost import contracts, is managed to complement the physical transaction portfolio, thereby reducing overall risks within limits. Therefore, the adverse impact to the fair value of the portfolio of Non-trading Energy Derivatives held for hedging purposes associated with the hypothetical changes in commodity prices referenced above would be offset by a favorable impact on the underlying hedged physical transactions, assuming:

- the Non-trading Energy Derivatives are not closed out in advance of their expected term;
- the Non-trading Energy Derivatives continue to function effectively as hedges of the underlying risk; and
- as applicable, anticipated underlying transactions settle as expected.

If any of the above-mentioned assumptions cease to be true, a loss on the derivative instruments may occur, or the options might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first. Non-trading Energy Derivatives intended as hedges, and which are effective as hedges, may still have some percentage which is not effective. The change in value of the Non-

trading Energy Derivatives which represents the ineffective component of the hedges, is recorded in our results of operations. During 2001, we recognized revenues of $8 million in our Statements of Consolidated Income due to hedge ineffectiveness.

Our European Energy business segment's stranded cost import contracts have exposure to commodity prices. For information regarding these contracts, please read Notes 5(b) and 14(h) to our consolidated financial statements. A decrease of 10% in market prices of energy commodities from their December 31, 2001 levels would result in a loss of earnings of $98 million.

Interest Rate Risk

We have issued long-term debt and have obligations under bank facilities that subject us to the risk of loss associated with movements in market interest rates. We utilize interest-rate swaps in order to hedge a portion of our floating-rate obligations.

We have outstanding long-term debt and commercial paper obligations under bank facilities, mandatory redeemable preferred securities of subsidiary trusts holding solely our junior subordinated debentures (Trust Preferred Securities), securities held in our nuclear decommissioning trust, some lease obligations and our obligations under the ZENS that subject us to the risk of loss associated with movements in market interest rates. We utilize interest-rate swaps in order to hedge portions of our floating-rate debt and to hedge a portion of the interest rate applicable to a future offering of long-term debt.

Our floating-rate obligations aggregated $5.8 billion and $4.2 billion at December 31, 2000 and 2001, respectively. If the floating interest rates were to increase by 10% from December 31, 2001 rates, our combined interest expense would increase by a total of $1.2 million each month in which such increase continued.

At December 31, 2000 and 2001, we had outstanding fixed-rate debt (excluding indexed debt securities) and Trust Preferred Securities aggregating $5.5 billion and $6.2 billion, respectively, in principal amount and having a fair value of $6.2 billion each year. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Notes 10 and 11 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $682 million if interest rates were to decline by 10% from their levels at December 31, 2001. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity.

As discussed in Note 14(k) to our consolidated financial statements, we contributed $14.8 million in 1999, 2000 and 2001 to a trust established to fund our share of the decommissioning costs for the South Texas Project. In 2002, we will begin contributing $2.9 million per year to this trust. The securities held by the trust for decommissioning costs had an estimated fair value of $169 million as of December 31, 2001, of which approximately 46% were fixed-rate debt securities that subject us to risk of loss of fair value with movements in market interest rates. If interest rates were to increase by 10% from their levels at December 31, 2001, the decrease in fair value of the fixed-rate debt securities would not be material to us. In addition, the risk of an economic loss is mitigated. Any unrealized gains or losses are accounted for in accordance with SFAS No. 71 as a regulatory asset/liability because we believe that our future contributions, which are currently recovered through the ratemaking process, will be adjusted for these gains and losses. For further discussion regarding the recovery of decommissioning costs pursuant to the Texas Electric Restructuring Law, please read Note 4(a) to our consolidated financial statements.

As discussed in Note 10(b) to our consolidated financial statements, RERC Corp.'s $500 million aggregate principal amount of 6¾% Term Enhanced Remarketable Securities (TERM Notes) include an embedded option to remarket the securities. The option is expected to be exercised in the event that the ten-year Treasury rate in 2003 is below 5.66%. At December 31, 2001, we could terminate the option at a cost of $21 million. A decrease of 10% in the December 31, 2001 level of interest rates would increase the cost of termination of the option by approximately $16 million.

As discussed in Note 8 to our consolidated financial statements, upon adoption of SFAS No. 133 effective January 1, 2001, the ZENS obligation was bifurcated into a debt component of $122 million and a derivative component of $788 million. The debt component of $122 million is a fixed-rate obligation and, therefore, does not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by approximately $18 million if interest rates were to decline by 10% from levels at December 31, 2001. Changes in the fair value of the derivative component will be recorded in our Statements of Consolidated Income and, therefore, we are exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from December 31, 2001 levels, the fair value of the derivative component would increase by approximately $10 million, which would be recorded as a loss in our Statements of Consolidated Income.

During 2001, we entered into interest rate swaps having an aggregate notional amount of $1.8 billion to fix the interest rate applicable to floating rate short-term debt and interest rate swaps of $425 million to fix the interest rate applicable to floating rate long-term debt. At December 31, 2001, the swaps relating to short-term debt could be terminated at a cost of $12 million and the swaps related to long-term debt, of which $225 million had expired as of December 31, 2001, could be terminated at a cost of $4 million. The swaps relating to short-term debt do not qualify as cash flow hedges under SFAS No. 133, and are marked to market in our Consolidated Balance Sheets with changes reflected in interest expense in the Statements of Consolidated Income. The swaps relating to long-term debt qualify for hedge accounting under SFAS No. 133 and the periodic settlements are recognized as an adjustment to interest expense in the Statements of Consolidated Income over the term of the swap agreement. A decrease of 10% in the December 31, 2001 level of interest rates would increase the cost of terminating the swaps related to short-term debt and long-term debt outstanding at December 31, 2001 by $4 million each.

During 2001, we entered into forward-starting interest rate swaps having an aggregate notional amount of $500 million to hedge the interest rate on a future offering of five-year notes. At December 31, 2001, these swaps could be terminated at a cost of $2 million. These swaps qualify as cash flow hedges under SFAS No. 133. Should the expected issuance of the debt no longer be probable, any deferred amount will be recognized immediately into income. A decrease of 10% in the December 31, 2001 level of interest rates would increase the cost of terminating these swaps by $12 million.

For information regarding the accounting for these interest rate swaps, please read Note 5 to our consolidated financial statements.

Foreign Currency Exchange Rate Risk

Our European operations expose us to risk of loss in the fair value of our foreign investments due to the fluctuation in foreign currencies relative to our reporting currency, the U.S. dollar. Additionally, our European Energy business segment transacts in several European currencies, although the majority of its business is conducted in the Euro and prior to January 2001, the Dutch Guilder. As of December 31, 2001, we had entered into foreign currency swaps and foreign currency forward contracts and had issued Euro-denominated borrowings to hedge our foreign currency exposure of our net European investment. Changes in the value of the foreign currency hedging instruments and Euro — denominated borrowings are recorded as foreign currency translation adjustments as a component of accumulated other comprehensive income (loss) in stockholders' equity. As of December 31, 2000 and 2001, we had recorded a loss of $2 million and $96 million, respectively, in cumulative net translation adjustments. The cumulative translation adjustments will be realized in earnings and cash flows only upon the disposition of the related investments. During the normal course of business, we review our currency hedging strategies and determine the hedging approach we deem appropriate based upon the circumstances of each situation.

As of December 31, 2001, our European Energy business segment had entered into transactions to purchase $271 million at fixed exchange rates in order to hedge future fuel purchases payable in U.S. dollars. As of December 31, 2001, the fair value of these financial instruments was a $3 million asset. An increase in

the value of the Euro of 10% compared to the U.S. dollar from its December 31, 2001 level would result in loss in the fair value of these foreign currency financial instruments of $27 million.

Our European Energy business segment's stranded cost import contracts have foreign currency exposure. An increase of 10% in the U.S. dollar relative to the Euro from their December 31, 2001 levels would result in a loss of earnings of $6 million.

Beginning in January 2002, our remaining Latin America operations will use the Argentine peso as their functional currency (please read Note 2(o) to our consolidated financial statements). These foreign operations will expose us to risk of loss in earnings and cash flows due to the fluctuation in foreign currencies relative to our consolidated reporting currency, the U.S. dollar. We account for adjustments resulting from translation of our investments with functional currencies other than the U.S. dollar as a charge or credit directly to a separate component of stockholders' equity.

Equity Market Value Risk

We are exposed to equity market value risk through our ownership of approximately 26 million shares of AOL TW Common, which are held by us to facilitate our ability to meet our obligations under the ZENS. Please read Note 8 to our consolidated financial statements for a discussion of the effect of adoption of SFAS No. 133 on our ZENS obligation and our historical accounting treatment of our ZENS obligation. Subsequent to adoption of SFAS No. 133, a decrease of 10% from the December 31, 2001 market value of AOL TW Common would result in a net loss of approximately $3 million, which would be recorded as a loss in our Statements of Consolidated Income.

As discussed above under "— Interest Rate Risk," we contribute to a trust established to fund our share of the decommissioning costs for the South Texas Project, which held debt and equity securities as of December 31, 2001. The equity securities expose us to losses in fair value. If the market prices of the individual equity securities were to decrease by 10% from their levels at December 31, 2001, the resulting loss in fair value of these securities would not be material to us. Currently, the risk of an economic loss is mitigated as discussed above under "— Interest Rate Risk."

We have equity investments, which are classified as "available-for-sale" under SFAS No. 115. As of December 31, 2001, the value of these securities was $12 million. A 10% decline in the market value per share of these securities from December 31, 2001 would result in a loss in fair value of $1 million.

Risk Management Structure

We have a risk control framework to limit, monitor, measure and manage the risk in our existing portfolio of assets and contracts and to risk-measure and authorize new transactions. These risks include market, credit, liquidity and operational exposures. We believe that we have effective procedures for evaluating and managing these risks to which we are exposed. Key risk control activities include limits on trading and marketing exposures and products, credit review and approval, credit and performance risk measurement and monitoring, validation of transactions, portfolio valuation and daily portfolio reporting including mark-to-market valuation, VAR and other risk measurement metrics.

We seek to monitor and control our risk exposures through a variety of separate but complementary processes and committees which involve business unit management, senior management and our board of directors, as detailed below.

Board of Directors. Our board of directors affirms the overall strategy and approves overall risk limits for commodity trading and marketing.

Audit Committee. The Audit Committee of our board of directors assesses the adequacy of the risk control organization and policies. The Audit Committee of our board of directors meets at least four times a year to:

- approve the risk control organization structure;
- approve the corporate-wide risk control policy;
- monitor compliance with trading limits;
- review significant risk control issues; and
- recommend to our board of directors corporate-wide commodity risk limit parameters for trading and marketing activities.

Executive Management. Our executive management appoints the Risk Oversight Committee members, reviews and approves recommendations of the Risk Oversight Committee prior to presentations to the Audit Committee of our board of directors, and approves and monitors broad risk limit allocations to the business segments and product types. Our executive management receives daily position reports of our trading and marketing activities.

Risk Oversight Committee. The Risk Oversight Committee, which is comprised of corporate and business segment officers, oversees all of our trading, marketing and hedging activities and other activities involving market risks. These activities expose us to commodity price, credit, foreign currency and interest rate risks. The Risk Oversight Committee meets at least monthly. For trading, marketing and hedging activities, the Risk Oversight Committee:

- monitors compliance of our trading units;
- reviews daily position reports for trading and marketing activities;
- recommends adjustments to trading limits, products and policies to the Audit Committee of our board of directors;
- approves business segment's detailed policies and procedures;
- allocates board of director-approved trading and marketing risk capital limits, including VAR limits;
- approves new trading, marketing and hedging products and commodities;
- approves entrance into new trading markets;
- monitors processes and information systems related to the management of our risk to market exposures; and
- places guidelines and limits around hedging activities.

Commitment Review Committee. The Commitment Review Committee, which is comprised of corporate officers, establishes corporate-wide standards for the evaluation of capital projects and other significant commitments, evaluates proposed capital projects and other significant commitments, and makes recommendations to the chief executive officer. The Commitment Review Committee is scheduled to meet on an as needed basis.

Corporate Risk Control Organization. Our Corporate Risk Control Organization is headed by a chief risk control officer who has corporate-wide oversight for maintaining consistent application of corporate risk policies within individual business segments. The Corporate Risk Control Organization:

- recommends the corporate-wide risk management policies and procedures which are approved by the Audit Committee of our board of directors;
- provides updates of trading and marketing activities to the Audit Committee of our board of directors on a regular basis;

- provides oversight of our ongoing development and implementation of operational risk policies, framework and methodologies;
- monitors effectiveness of the corporate-wide risk management policies, procedures and risk limits;
- evaluates the business segment risk control organizations, including information systems and reporting;
- evaluates all significant valuation methodologies, assumptions and models;
- evaluates allocation of risk limits within our business segments;
- reviews daily position reports of trading and marketing activities; and
- reviews inherent risks in proposed transactions.

Business Segment Risk Control Organizations. The Corporate Risk Control Organization also serves as the risk control organization for the business segments that will comprise CenterPoint Energy. Each of Reliant Resources' business segments has a Business Segment Risk Control Organization, which is headed by a risk control officer who reports to the Corporate Risk Control Organization and the business segment's executive management outside of the commercial trading organization. The Business Segment Risk Control Organization:

- develops and maintains the risk control infrastructure, including policies, processes, personnel and information and valuation systems, to analyze and report the daily risk positions to Executive Management, the Risk Oversight Committee, the Corporate Risk Control Organization, the Internal Audit Department and the Controllers Organization;
- reviews credit exposures for customers and counterparties;
- reviews all significant valuation methodologies, assumptions and models used for risk measurement, mark-to-market valuations and structured transaction evaluations;
- ensures that risk systems can adequately measure positions and related risk exposures for new products and transactions;
- evaluates new transactions for compliance with risk policies and limits; and
- evaluates effectiveness of hedges.

The management of each of the business segments is responsible for the management of its risks and for maintaining an environment conducive to effective risk control activities as part of its overall responsibility for the business unit. Commercial management has in-depth knowledge of the primary sources of risk in their individual markets and the instruments available to hedge our exposures. Commercial management assigns risk limits that have been allocated to specific markets and to individual traders, within the limits imposed by the Risk Oversight Committee. Risk limits are monitored on a daily basis. Risk limit violations, including VAR, are reported to the appropriate level of management in the business segment, the Corporate Risk Control Organization, the Risk Oversight Committee, the board of directors and the Audit Committee of the board of directors.

Segregation of duties and management oversight are fundamental elements of our risk management process. There are segregation of duties among the trading and marketing functions; transaction validation and documentation; risk measurement and reporting; settlements function; accounting and financial reporting functions; and treasury function. These risk management processes and related controls are reviewed by our corporate Internal Audit Department on a regular basis. When appropriate, external advisors or consultants with relevant experience will assist the Internal Audit Department with their reviews.

The effectiveness of our policies and procedures for managing risk exposure can never be completely measured or fully assured. For example, we could experience losses which could have a material adverse effect on our financial condition, results of operations or cash flows, from unexpectedly large or rapid movements or disruptions in the energy markets, from regulatory-driven market rules changes, and bankruptcy of customers or counterparties.

Credit Risk

Credit risk is inherent in our commercial activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. Broad credit policies and parameters are set by the Risk Oversight Committee. The Business Segment Risk Control Organizations prepare daily analyses of credit exposures. We enter into derivative instruments primarily with counterparties having a minimum investment grade credit rating (*i.e.*, a minimum credit rating for such entity's senior unsecured debt of BBB- for Standard & Poor's and Fitch or Baa3 for Moody's). In addition, we seek to enter into netting agreements that permit us to offset receivables and payables with a given counterparty. We also attempt to enter into agreements that enable us to either obtain collateral from a counterparty or to terminate upon the occurrence of adverse credit-related events. We are re-evaluating our current credit risk practices in light of changes in the marketplace, recent corporate failures and changing credit practices by the rating agencies.

It is our policy that all transactions must be within approved counterparty or customer credit limits. For each business segment, counterparty credit limits are established by the applicable business segment's credit risk control group. We employ tiered levels of approval authority for counterparty credit limits, with authority increasing from the operating business segment's credit analysts through the business segment's risk control officer, the Risk Oversight Committee and our executive management. The Business Segment Risk Control Organization monitors credit exposure daily. The mark-to-market values and cash settlement values for all transactions are compared to the authorized credit threshold for each counterparty. For long-term arrangements, we periodically review the financial condition of these counterparties in addition to monitoring the effectiveness of these contracts in achieving our objectives.

For information regarding our provision related to our energy sales in the California market, please read Note 14(g) to our consolidated financial statements. For information regarding our net provision related to energy sales to Enron which filed a voluntary petition for bankruptcy, please read Note 21 to our consolidated financial statements.

The following table presents the distribution by credit ratings of our total trading and marketing assets and total non-trading derivative assets as of December 31, 2001, after taking into consideration netting and set-off agreements with counterparties within each balance sheet caption (in millions).

Credit Rating Equivalent	Exposure	Collateral Held(3)	Exposure Net of Collateral	Percentage of Exposure Net of Collateral
AAA/Aaa	$ 136	$ —	$ 136	5%
AA/Aa2	191	—	191	7%
A/A2	1,049	(4)	1,045	39%
BBB/Baa2	1,152	(137)	1,015	38%
BB/Ba2 or lower	251	(26)	225	9%
Unrated(1)(2)	49	—	49	2%
	2,828	(167)	2,661	100%
Less: Credit and other reserves	114	—	114	
	$2,714	$(167)	$2,547	

The following table presents credit exposure by maturity for total trading and marketing assets and non-trading derivative assets, net of collateral, as of December 31, 2001 (in millions).

Credit Rating Equivalent	0-12 Months	1 Year or Greater	Exposure Net of Collateral
AAA/Aaa	$ 95	$ 41	$ 136
AA/Aa2	142	49	191
A/A2	860	185	1,045
BBB/Baa2	660	355	1,015
BB/Ba2 or lower	125	100	225
Unrated(1)(2)	31	18	49
	1,913	748	2,661
Less: Credit and other reserves	69	45	114
	$1,844	$703	$2,547

(1) For unrated counterparties, we perform financial statement analysis, considering contractual rights and restrictions, and collateral, to create a synthetic credit rating.

(2) In lieu of making an individual assessment of the credit of unrated counterparties, we may make a determination that the collateral held in respect of such obligations is sufficient to cover a substantial portion of our exposure. In making this determination, we take into account various factors, including market volatility.

(3) Collateral consists of cash and standby letters of credit.