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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2003

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 1-16455

Reliant Resources, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**76-0655566** *(I.R.S. Employer Identification No.)*
1000 Main Street, Houston, Texas 77002 *(Address and Zip Code of Principal Executive Offices)*	**(713) 497-3000** *(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, par value $.001 per share, and associated rights to purchase Series A Preferred Stock	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 the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K/A or any amendment to this Form 10-K/A. ☑

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ☑ No ☐

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $1,788,989,958 (computed by reference to the closing sale price of the Registrant's common stock on the New York Stock Exchange on June 30, 2003). As of March 1, 2004, the Registrant had 295,539,205 shares of common stock outstanding, excluding 4,264,795 shares of common stock held by the Registrant as treasury stock.

Portions of the definitive proxy statement relating to the 2004 Annual Meeting of Stockholders of the Registrant's, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2003, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

TABLE OF CONTENTS

		Page
Cautionary Statement Regarding Forward-Looking Information		1
Glossary of Terms		2
PART I		
Item 1.	Business	6
	Our Business	6
	General	6
	Retail Energy	6
	Residential and Small Commercial Services — Services Business	6
	Commercial, Industrial and Institutional Services — Solutions Business	6
	Retail Energy Supply	7
	Regulation	7
	Competition	9
	Wholesale Energy	9
	Mid-Atlantic Region	11
	New York Region	13
	Mid-Continent Region	14
	Southeast Region	15
	West Region	16
	ERCOT Region	18
	Commercial Operations	18
	Regulation	19
	Competition	20
	Other Operations	20
	Environmental Matters	20
	Employees	24
	Executive Officers	24
	Available Information	26
	Stockholder Communications with the Board of Directors	26
Item 2.	Properties	27
Item 3.	Legal Proceedings	27
Item 4.	Submission of Matters to a Vote of Security Holders	27
PART II		
Item 5.	Market for Our Common Equity and Related Stockholder Matters	27
Item 6.	Selected Financial Data	29
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	32
	Overview	32
	Consolidated Results of Operations	34
	2003 Compared to 2002	34
	2002 Compared to 2001	35

		Page
	EBIT by Business Segment	36
	Retail Energy	38
	Wholesale Energy	43
	Other Operations	50
	Risk Factors	51
	Risks Relating to Selling Electricity	51
	Risks Relating to Ownership of Generation Assets	53
	Regulatory Risks	53
	Special Risks Relating to the Texas Market	54
	Risks Related to our Capital Structure	56
	General Business Risks	58
	Liquidity and Capital Resources	59
	Sources of Liquidity and Capital Resources	59
	Liquidity and Capital Requirements	61
	Off-Balance Sheet Arrangements	63
	Historical Cash Flows	64
	New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates	69
	New Accounting Pronouncements	69
	Significant Accounting Policies	69
	Critical Accounting Estimates	69
	Related Party Transactions	75
Item 7A.	Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks	76
	Market Risk and Risk Management	76
	Non-trading Market Risk	76
	Trading Market Risk	79
	Credit Risk	83
Item 8.	Financial Statements and Supplementary Data	F-1
	Reliant Resources, Inc. and Subsidiaries Consolidated Financial Statements	F-4
	Reliant Resources, Inc. — Schedule I — Condensed Financial Information of Registrant	F-107
	Reliant Resources, Inc. and Subsidiaries — Schedule II — Reserves	F-116
	Reliant Energy Retail Holdings, LLC and Subsidiaries Consolidated Financial Statements	F-117
	Reliant Energy Mid-Atlantic Power Holdings, LLC and Subsidiaries Consolidated Financial Statements	F-148
	Orion Power Holdings, Inc. and Subsidiaries Consolidated Financial Statements	F-177
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	II-1
Item 9A.	Controls and Procedures	II-1
	Evaluation of Disclosure Controls and Procedures	II-1
	Changes in Internal Controls	II-1

		Page
	PART III	
Item 10.	Directors and Executive Officers	III-1
Item 11.	Executive Compensation	III-1
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	III-1
Item 13.	Certain Relationships and Related Transactions	III-1
Item 14.	Principal Accountant Fees and Services	III-1
	PART IV	
Item 15.	Exhibits, Financial Statement Schedules and Reports on Form 8-K	IV-1

Cautionary Statement Regarding Forward-Looking Information

When we make statements containing projections, estimates or assumptions about our revenues, income and other financial items, our plans for the future, future economic performance, transactions for the sale of parts of our operations and financings related thereto, we are making "forward-looking statements." Forward-looking statements relate to future events and anticipated revenues, earnings, business strategies, competitive position or other aspects of our operations or operating results. In many cases you can identify forward-looking statements by terminology such as "anticipate," "estimate," "believe," "continue," "could," "intend," "may," "plan," "potential," "predict," "should," "will," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and other similar words. However, the absence of these words does not mean that the statements are not forward-looking. Although we believe that the expectations and the underlying assumptions reflected in our forward-looking statements are reasonable, there can be no assurance that these expectations will prove to be correct. Forward-looking statements are not guarantees of future performance or events. Such statements involve a number of risks and uncertainties, and actual results may differ materially from the results discussed in the forward-looking statements.

Among other things, the matters described in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors" in Item 7 of this report and note 15 to our consolidated financial statements could cause actual results to differ materially from those expressed or implied in our 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 statement, whether as a result of new information, future events or otherwise.

Glossary of Terms

The following terms are used in this report:

APB No. 25	Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."
Bcf	one billion cubic feet of natural gas.
Cal ISO	California Independent System Operator.
Cal PX	California Power Exchange.
CDWR	California Department of Water.
CenterPoint	CenterPoint Energy, Inc., on and after August 31, 2002 and Reliant Energy, Incorporated prior to August 31, 2002.
CenterPoint Plans	CenterPoint Long-Term Incentive Compensation Plan and certain other incentive compensation plans of CenterPoint.
CERCLA	Comprehensive Environmental Response Corporation and Liability Act of 1980.
CFTC	Commodity Futures Trading Commission.
Channelview	Reliant Energy Channelview L.P.
CO_2	Carbon dioxide.
Distribution	the distribution of approximately 83% of our common stock owned by CenterPoint to its stockholders on September 30, 2002.
EBIT	earnings (loss) before interest expense, interest income and income taxes.
EBITDA	earnings (loss) before interest expense, interest income, income taxes, depreciation and amortization expense.
ECAR Market	the wholesale electric market operated by East Central Area Reliability Coordination Council.
EITF	Emerging Issues Task Force.
EITF No. 98-10	EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities."
EITF No. 02-03	EITF Issue No. 02-03, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities."
EITF No. 03-11	EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in EITF Issue No. 02-03."
Enron	Enron Corp. and its affiliates.
EPA	United States Environmental Protection Agency.
ERCOT	Electric Reliability Council of Texas.
ERCOT ISO	ERCOT Independent System Operator.

ERCOT Region	the electric market operated by ERCOT.
ESPP	Reliant Resources Employee Stock Purchase Plan.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FIN No. 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Direct Guarantees of Indebtedness of Others."
FIN No. 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51."
FIN No. 46R	FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51."
GAAP	United States generally accepted accounting principles.
GWh	gigawatt hour.
IPO	our initial public offering in May 2001.
ISO	independent system operator.
KWh	kilowatt hour.
LEP	Liberty Electric Power, LLC, one of our subsidiaries.
Liberty	Liberty Electric PA, LLC, one of our subsidiaries.
LIBOR	London inter-bank offered rate.
MACT	Maximum Achievable Control Technology.
MAIN Market	the wholesale electric market operated by Mid-America Interconnected Network.
MISO	Midwest Independent Transmission System Operator.
MISO Market	the wholesale electric market operated by MISO, primarily in all parts of Iowa, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota and South Dakota.
MMbtu	one million British thermal units.
MW	megawatts.
MWh	megawatt hour.
NEA	NEA, B.V., formerly the coordinating body for the Dutch electric generating sector.
NO_x	Nitrogen oxides.
NYISO	New York Independent System Operator.
NY Market	the wholesale electric market operated by NYISO in the state of New York.
Orion Capital	Orion Power Capital, LLC, one of our subsidiaries.
Orion MidWest	Orion Power MidWest, L.P., one of our subsidiaries.
Orion NY	Orion Power New York, L.P., one of our subsidiaries.

Orion Power	Orion Power Holdings and its subsidiaries.
Orion Power Holdings	Orion Power Holdings, Inc., one of our subsidiaries.
OTC	over-the-counter market.
PEDFA	Pennsylvania Economic Development Financing Authority.
PG&E	Pacific Gas and Electric.
PJM	PJM Interconnection, LLC.
PJM Market	the wholesale electric market operated by PJM primarily in all or parts of Delaware, the District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia.
POLR	provider of last resort.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act of 1935.
QSPE	qualified special purpose entity.
RE BV	Reliant Energy Europe B.V., formerly one of our subsidiaries.
RECE	Reliant Energy Capital (Europe), Inc., one of our subsidiaries.
Reliant Energy	Reliant Energy, Incorporated and its subsidiaries.
Reliant Energy Services	Reliant Energy Services, Inc., one of our subsidiaries.
Reliant Resources	Reliant Resources, Inc.
REMA	Reliant Energy Mid-Atlantic Power Holdings, LLC, one of our subsidiaries, and its subsidiaries.
REPG	Reliant Energy Power Generation, Inc., one of our subsidiaries.
REPGB	Reliant Energy Power Generation Benelux, B.V., formerly one of our subsidiaries.
RTO	regional transmission organizations.
SCE	Southern California Edison Company.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards.
SFAS No. 123	SFAS No. 123, "Accounting for Stock Based Compensation."
SFAS No. 132	SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits."
SFAS No. 132 (Revised 2003)	SFAS No. 132 (Revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits — An Amendment of FASB Statements No. 87, 88 and 106."
SFAS No. 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.
SFAS No. 141	SFAS No. 141, "Business Combinations."
SFAS No. 142	SFAS No. 142, "Goodwill and Other Intangible Assets."
SFAS No. 143	SFAS No. 143, "Accounting for Asset Retirement Obligations."

SFAS No. 144	SFAS No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets."
SFAS No. 148	SFAS No. 148, "Accounting for Stock Based Compensation — Transition and Disclosure, an amendment to SFAS No. 123."
SFAS No. 149	SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities."
SO_2	Sulfur dioxide.
Spark spread	the difference between power prices and natural gas fuel costs.
SRP	Salt River Agricultural Improvement and Power District.
Texas electric restructuring law	Texas Electric Choice Plan adopted by the Texas legislature in June 1999.
Texas Genco	Texas Genco, LP and its subsidiaries and Texas Genco Holdings, Inc., and its subsidiaries.
Texas Genco Holdings, Inc	a majority-owned subsidiary of CenterPoint.
Texas Genco, LP	a subsidiary of Texas Genco Holdings, Inc.

PART I

Item 1. *Business.*

Our Business

General

"Reliant Resources" refers to Reliant Resources, Inc. and "we," "us" and "our" refer to Reliant Resources, Inc. and its consolidated subsidiaries, unless we specify or the context indicates otherwise.

Our business operations consist of two principal business segments:

- *Retail energy* — provides electricity and related services to retail customers primarily in Texas and acquires and manages the electric energy, capacity and ancillary services associated with supplying these retail customers; and
- *Wholesale energy* — provides electric energy, capacity and ancillary services in the competitive segments of the United States' wholesale energy markets.

Our remaining operations include unallocated corporate functions and minor equity and other investments. For information regarding our corporate history, including the sale of our European energy operations in 2003, see notes 1 and 22 to our consolidated financial statements.

Retail Energy

Our retail energy segment provides electricity products and services to end-use customers, ranging from residential and small commercial customers to large commercial, industrial and institutional customers. The operations of our retail energy segment are primarily in Texas. In 2003, we began providing retail energy products and services to small and large commercial, industrial and institutional customers in New Jersey and Maryland. In 2004, we intend, to the extent market conditions are attractive, to begin retail energy sales to commercial, industrial and institutional customers in other areas of the PJM Market, including Pennsylvania. We are also evaluating the possibility of making similar sales to customers in the MISO Market.

Residential and Small Commercial Services — Services Business

In Texas, we provide standardized electricity and related products and services to residential and small commercial customers with a peak demand for power up to approximately one MW. As of December 31, 2003, we had approximately 1.6 million residential customers and 210,000 small commercial accounts in Texas, making us the second largest retail electric provider in the state. The majority of our customers are in the Houston area, but we also have customers in other areas, including Dallas and Corpus Christi, Texas.

In the Houston area, the Texas electric restructuring law currently requires us, as a former affiliate of the transmission and distribution utility in Houston, to sell electricity to residential customers only at a specified price, or "price-to-beat." Outside of the Houston area, we are generally permitted to sell electricity at unregulated prices to residential and small commercial customers. For information regarding the PUCT regulation of pricing to residential and small commercial customers, see "— Regulation" below.

We currently provide retail electric service to residential customers only in Texas. We have no near-term plans to provide retail electric service to residential customers outside of Texas.

Commercial, Industrial and Institutional Services — Solutions Business

In Texas, we market electricity and energy services to large commercial, industrial and institutional customers, i.e., customers with a peak demand of greater than approximately one MW. In New Jersey and Maryland, we market electricity and energy services to commercial, industrial and institutional customers.

Our commercial, industrial and institutional customers include refineries, chemical plants, manufacturing facilities, hospitals, universities, governmental agencies, restaurants and other facilities. In general, we sell electricity to these customers at unregulated prices.

As of December 31, 2003, we had contracts to provide an aggregate of 5,735 MW of electricity to approximately 820 customers in Texas and an aggregate of 490 MW of electricity to approximately 120 customers in the PJM Market. The terms of our contracts range from 1 to 51 months, with the average term being 21 months. We also provide customized energy solutions, including energy information services and products, to our commercial, industrial and institutional customers. For information regarding revenues from end-use retail customers, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Retail Energy."

Retail Energy Supply

In Texas, we must purchase from third parties substantially all of the generation capacity necessary to supply our retail energy business. As of February 20, 2004, we had entered into contracts to purchase generation capacity averaging 9,944 MW per month in 2004, 2,914 MW per month in 2005 and 1,000 MW per month in 2006. Based on current market conditions, existing retail sales commitments and current load forecasts, we estimate that these contracts will supply approximately 87% of the current capacity requirements of our retail energy business for the remainder of 2004 and 47% of our estimated 2005 requirements.

The largest supplier of generation capacity for our Texas retail energy business was Texas Genco. We expect to continue to contract with third parties, including Texas Genco, for a significant portion of our Texas retail energy business' power requirements, including purchases pursuant to power purchase agreements and auctions of power conducted by Texas generation companies. In addition, we may seek to supplement our market-based purchases of power over time with the purchase of individual generation assets.

In January 2004, we elected not to exercise our option to purchase CenterPoint's ownership interest in Texas Genco. For information regarding our decision not to exercise the option to purchase CenterPoint's interest in Texas Genco, see note 4 to our consolidated financial statements.

In states outside of Texas, we generate sufficient capacity to supply our retail needs.

Regulation

Texas Public Utility Commission. We are, through our operating subsidiaries, certified to provide retail electric service to residential, small commercial and large commercial, industrial and institutional customers in Texas.

The Texas electric restructuring law currently regulates the prices at which we can sell electricity to residential and small commercial customers. Outside of the Houston area, we generally are permitted to sell electricity at unregulated prices to these customers. However, in the Houston area, we can sell electricity to residential customers only at a specified price, or "price-to-beat." This requirement will continue until January 1, 2005, at which time we will also be able to sell at prices other than the price-to-beat. Starting January 1, 2007, we will be able to sell without pricing restrictions.

Prior to January 2004, we were required to sell electricity to small commercial customers in the Houston area only at the price-to-beat. However, that restriction has expired. We are now able to sell electricity without pricing restrictions so long as we continue to make the price-to-beat available as an alternative for Houston area customers until January 1, 2007. As of December 31, 2003, the prices-to-beat for residential customers and small commercial customers were 11.05 cents per KWh for a residential customer using 1,000 KWh per month and 8.54 cents per KWh for a small commercial customer using 15,000 KWh per month.

The price-to-beat includes a base rate component established by the PUCT in 1999 and an adjustable energy supply component or fuel factor. We can apply for adjustments in the fuel factor twice a year based on changes in the average 12-month forward price of natural gas or changes in the price of purchased energy. In 2003, we requested, and the PUCT approved, two adjustments to our price-to-beat fuel factor resulting in an 18% increase of our residential price-to-beat in that year. During 2002 and 2003, we requested, and the PUCT approved, two adjustments in each period to our price-to-beat fuel factor as follows:

Date Requested	Date Granted	Natural Gas Price in Fuel Factor Before Request (per MMbtu)	Natural Gas Price in Fuel Factor After Request (per MMbtu)
May 2002	August 2002	$3.110	$3.729
November 2002	December 2002	$3.729	$4.017
January 2003	March 2003	$4.017	$4.956
June 2003	July 2003	$4.956	$6.100

In 2004, the PUCT will determine the "stranded costs" of Texas transmission and distribution utilities in accordance with procedures established under the Texas electric restructuring law. Following this determination, we expect that the PUCT will review our price-to-beat. If at that time the average 12-month forward price of natural gas is lower than the average price reflected in our then current price-to-beat fuel factor, we expect the PUCT to lower our price-to-beat fuel factor. In addition, we expect that the PUCT will adjust at that time the base rate component of our price-to-beat that reflects the non-bypassable rates that Texas transmission and distribution utilities charge us to include any stranded cost charges. Non-bypassable rates include various fixed charges established by the PUCT under the Texas electric restructuring law. We estimate that the PUCT review of our price-to-beat will occur in the fourth quarter of 2004 or the first quarter of 2005. We cannot, however, predict at this time the outcome of the PUCT's review.

The Texas electric restructuring law requires that we make a payment to CenterPoint unless, as of December 31, 2003, retail electric providers other than us supplied 40% or more of the electricity consumed by Houston area residential customers. We estimate the payment to be $175 million and expect that the payment will be made in the fourth quarter of 2004. For information regarding our accruals for this payment, see note 14(d) to our consolidated financial statements.

ERCOT ISO. We are a member of ERCOT. Members of ERCOT include retail customers, both investor and municipal owned electric utilities, rural electric cooperatives, river authorities, independent generators, power marketers and retail electric providers.

The ERCOT ISO is responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT Region. Its responsibilities include ensuring that information relating to a customer's choice of retail electric provider is conveyed in a timely manner. It is also responsible for ensuring that electricity production and delivery are accurately allocated and settled among the generation resources and wholesale buyers and sellers in the ERCOT Region.

For additional information regarding ERCOT, including information regarding problems experienced in ERCOT information systems, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors" in Item 7 of this report.

Regulation in Other States. We are registered to sell electricity to commercial, industrial and institutional customers in the District of Columbia, New Jersey, Maryland and Pennsylvania. In each of these states, we are generally permitted under local public utility commission regulations to sell electricity at market rates.

Competition

For information regarding competitive factors affecting our retail energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors" in Item 7 of this report.

Wholesale Energy

We have a portfolio of electric power generation facilities. Because our facilities are not subject to traditional cost-based regulation, we can generally sell electricity at market prices. We market electric energy, capacity and ancillary services. We procure natural gas, coal, fuel oil, natural gas transportation and storage capacity and other energy-related commodities to supply and manage our physical assets. In March 2003, we discontinued our proprietary trading business. Trading positions taken prior to our decision to exit this business are managed solely for purposes of closing them on economical terms.

As of December 31, 2003, we owned, had an interest in, or leased 124 operating electric power generation facilities with an aggregate net generating capacity of 19,442 MW in six regions of the United States. The generating capacity of our facilities consists of approximately 30% of base-load (5,910 MW), 40% of intermediate (7,689 MW) and 30% of peaking capacity (5,843 MW). As of December 31, 2003, we had under construction 1,111 MW of additional base-load net generating capacity. One facility under construction (591 MW) reached commercial operation in February 2004. The other facility under construction is expected to reach commercial operation in the third quarter of 2004.

In 2003, we sold one facility having a total net generating capacity of 588 MW and retired from service a total of five power-generating units having a total net generating capacity of 579 MW. We currently have mothballed four units having a total net generation capacity of 824 MW. In February 2004, we announced our plans to mothball and/or retire an additional 20 generating units (727 MW) from certain peaking plants and units that serve the PJM Market subject to a review of certain reliability issues with regulators. Depending on future market conditions in the wholesale power industry, we may sell, retire, mothball or dispose of additional generation assets.

The following table describes our electric power generation facilities and net generating capacity by region (excluding generation facilities that we retired from service) as of December 31, 2003:

Region	Number of Generation Facilities	Generating Capacity (MW) (1)	Fuel Types Present	Dispatch Types
Mid-Atlantic				
Operating(2)	21	5,393	Coal/Hydro/Gas/Oil/Dual	Base, Intermediate, Peak
Under Construction(3)	1	520	Coal	Base
Combined	22	5,913		
New York				
Operating(4)	77	2,932	Hydro/Gas/Dual	Base, Intermediate, Peak
Mid-Continent				
Operating	9	4,473	Coal/Gas/Oil	Base, Intermediate, Peak
Southeast				
Operating(5)(6)	6	3,010	Gas/Dual	Base, Intermediate, Peak
West				
Operating(7)	4	2,803	Gas/Dual	Base, Intermediate
Mothballed	2	824	Gas	Intermediate, Peak
Under Construction(3)(8)	1	591	Gas	Base
Combined	7	4,218		
ERCOT				
Operating	7	831	Gas/Renewable	Base
Total				
Operating	124	19,442		
Mothballed	2	824		
Under Construction	2	1,111		
Combined	128	21,377		

(1) Generating capacity refers to the average of the facilities' summer and winter generating capacities net of auxiliary power.

(2) We lease a 100%, 16.67% and 16.45% interest in three Pennsylvania facilities having 614 MW, 1,704 MW and 1,714 MW of net generating capacity, respectively, through facility lease agreements expiring in 2026, 2034 and 2034, respectively. The table includes our share of the capacity of these facilities.

(3) 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 and prior to the commencement of commercial operations.

(4) Excludes two hydro plants with a total net generating capacity of 5 MW, which are not currently operational.

(5) We own a 50% interest in one of these facilities having a net generating capacity of 108 MW. An unaffiliated party owns the other 50%. The table includes only our share of the capacity of this facility.

(6) We are party to tolling agreements entitling us to 100% of the capacity of two Florida facilities having 630 MW and 474 MW of net generating capacity, respectively. These tolling agreements expire in 2012 and 2007, respectively, and are treated as operating leases for accounting purposes.

(7) We own a 50% interest in one Nevada facility having a net generating capacity of 470 MW. An independent third party owns the other 50%. The table includes our share of the capacity of this facility.

(8) Commenced commercial operation in February 2004.

The following table sets forth information regarding our generation output by dispatch type, fuel type and capacity factor during 2002 and 2003:

	2002	%	Capacity Factor(1)	2003	%	Capacity Factor(1)
Dispatch Type (GWh)						
Base-load	29,833	68	61%	34,429	75	65%
Intermediate	11,640	27	21%	9,470	21	15%
Peaking	2,302	5	4%	1,956	4	4%
Total	43,775	100%	28%	45,855	100%	27%
Sources of Electric Energy (GWh)						
Coal	22,185	51	60%	23,484	52	62%
Natural gas	12,404	28	20%	12,386	27	18%
Oil	31	—	1%	33	—	1%
Dual	6,365	15	13%	6,568	14	12%
Hydro	2,790	6	50%	3,258	7	55%
Renewables	—	—	—	126	—	55%
Total	43,775	100%	28%	45,855	100%	27%

(1) Capacity factor is the ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.

Mid-Atlantic Region

As of December 31, 2003, we owned, had an interest in, or leased 21 operating electric power generation facilities with an aggregate net generating capacity of 5,393 MW located in Pennsylvania, New Jersey and Maryland. The generating capacity of these facilities consists of approximately 34% of base-load (1,863 MW), 42% of intermediate (2,243 MW) and 24% of peaking capacity (1,287 MW).

We are constructing a 520 MW waste coal-fired base-load unit at an existing facility located in Pennsylvania that is expected to reach commercial operations in the third quarter of 2004. The 520 MW unit will replace two generating units at the facility that were retired in 2003. The retired generating units had 197 MW of total net generating capacity.

The following table describes the electric power generation facilities we owned, leased or had under construction in the Mid-Atlantic region (excluding generation facilities that we retired from service) as of December 31, 2003:

Generation Facilities	Location	Generating Capacity (MW) (1)	Fuel Types Present	Dispatch Types
Operating				
Blossburg(2)	Pennsylvania	23	Gas	Peak
Conemaugh(3)	Pennsylvania	282	Coal/Oil	Base/Peak
Deep Creek	Maryland	19	Hydro	Base
Gilbert(4)	New Jersey	615	Dual	Inter/Peak
Glen Gardner(2)	New Jersey	184	Dual	Peak
Hamilton	Pennsylvania	23	Oil	Peak
Hunterstown(5)	Pennsylvania	866	Gas/Dual	Inter/Peak
Keystone(3)	Pennsylvania	284	Coal/Oil	Base/Peak
Liberty	Pennsylvania	568	Gas	Base
Mountain	Pennsylvania	47	Dual	Peak
Orrtanna	Pennsylvania	23	Oil	Peak
Piney	Pennsylvania	28	Hydro	Base
Portland	Pennsylvania	584	Coal/Gas/Oil	Base/Inter/Peak
Sayreville(6)	New Jersey	496	Dual	Inter/Peak
Shawnee(2)	Pennsylvania	23	Oil	Peak
Shawville(3)	Pennsylvania	614	Coal/Oil	Base/Peak
Titus	Pennsylvania	281	Coal/Dual	Base/Peak
Tolna Station	Pennsylvania	47	Oil	Peak
Warren(2)	Pennsylvania	68	Dual	Peak
Wayne(7)	Pennsylvania	66	Oil	Peak
Werner(2)	New Jersey	252	Oil	Peak
Total Operating		5,393		
Under Construction				
Seward	Pennsylvania	520	Coal	Base
Total Combined		5,913		

(1) Generating capacity refers to the average of the facilities' summer and winter generating capacities net of auxiliary power.

(2) We announced in February 2004 that we intend to mothball this facility.

(3) We lease a 100% interest in the Shawville Station, a 16.67% interest in the Keystone Station and a 16.45% interest in the Conemaugh Station under facility interest lease agreements expiring in 2026, 2034 and 2034, respectively. The table includes our share of the capacity of these facilities.

(4) We announced in February 2004 that we intend to mothball approximately 111 MW of net generating capacity at this facility.

(5) PJM has informed us that, due to technical constraints within its transmission system, our 866 MW generation facility located at Hunterstown, Pennsylvania, cannot be dispatched during certain periods when high levels of electricity are flowing on the central interface. These conditions are generally experienced during periods of moderate electricity demands in the midwest with higher electricity demands in the east. We are in discussions with PJM and First EnergyCorp., the utility to which our plant interconnects, concerning a resolution of this constraint.

(6) In the first quarter of 2004, we retired two units with a total net generating capacity of 232 MW.

(7) We announced in February 2004 that we intend to retire this facility.

The following table sets forth information regarding our generation output in the Mid-Atlantic region by dispatch type, fuel type and capacity factor during 2002 and 2003:

	2002	%	Capacity Factor(1)	2003	%	Capacity Factor(1)
Dispatch Type (GWh)						
Base-load	11,112	87	60%	11,520	91	64%
Intermediate	1,480	12	14%	1,083	8	7%
Peaking	207	1	2%	110	1	1%
Total	12,799	100%	32%	12,713	100%	28%
Sources of Electric Energy (GWh)						
Coal	11,019	86	60%	11,385	90	65%
Natural gas	1,101	9	35%	722	6	9%
Oil	29	—	1%	29	—	1%
Dual	557	4	4%	442	3	3%
Hydro	93	1	23%	135	1	33%
Total	12,799	100%	32%	12,713	100%	28%

(1) Capacity factor is the ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.

New York Region

As of December 31, 2003, we owned 77 operating electric power generation facilities with an aggregate net generating capacity of 2,932 MW located in New York. Our generating facilities in the New York region consist of two distinct groups: (a) intermediate and peaking facilities located in New York City and (b) 73 run-of-river hydro facilities and one gas-fired facility located in central and northern New York State. The overall generating capacity of these facilities consists of approximately 21% of base-load (624 MW), 41% of intermediate (1,204 MW) and 38% of peaking capacity (1,104 MW).

The following table describes the electric power generation facilities we owned or leased in the New York region as of December 31, 2003:

Generation Facilities	Location	Generating Capacity (MW) (1)	Fuel Types Present	Dispatch Types
Operating				
Astoria	New York City	1,282	Gas/Dual	Inter/Peak
Carr Street	Syracuse, New York	99	Dual	Inter
Gowanus	New York City	610	Dual/Oil	Peak
Narrows	New York City	317	Dual	Peak
Hydroelectric assets(2)	Upstate New York	624	Hydro	Base
Total Operating		2,932		

(1) Generating capacity refers to the average of the facilities' summer and winter generating capacities net of auxiliary power.

(2) Excludes two hydro plants with a net generating capacity of 5 MW, which are not currently operational.

The following table sets forth information regarding our generation output in the New York region by dispatch type, fuel type and capacity factor during 2002 and 2003:

	2002(1)	%	Capacity Factor(2)	2003	%	Capacity Factor(2)
Dispatch Type (GWh)						
Base-load	2,697	44	52%	3,123	47	57%
Intermediate	2,995	49	30%	3,202	48	30%
Peaking	478	7	5%	311	5	3%
Total	6,170	100%	26%	6,636	100%	26%
Sources of Electric Energy (GWh)						
Natural gas	59	1	4%	56	1	4%
Dual	3,414	55	19%	3,457	52	19%
Hydro	2,697	44	52%	3,123	47	57%
Total	6,170	100%	26%	6,636	100%	26%

(1) Includes generation beginning in February 2002 in connection with our Orion Power acquisition. See note 5 to our consolidated financial statements.

(2) Capacity factor is the ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.

Mid-Continent Region

As of December 31, 2003, we owned nine electric power generation facilities with an aggregate net generating capacity of 4,473 MW located in Illinois, Ohio, Western Pennsylvania and West Virginia. The generating capacity of these facilities consists of approximately 52% of base-load (2,303 MW), 6% of intermediate (287 MW) and 42% of peaking capacity (1,883 MW).

The following table describes the electric power generation facilities we owned in the Mid-Continent region as of December 31, 2003:

Generation Facilities	Location	Generating Capacity (MW)(1)	Fuel Types Present	Dispatch Types
Operating				
Aurora	Illinois	912	Gas	Peak
Avon Lake	Ohio	721	Coal/Oil	Base/Peak
Brunot Island	Western Pennsylvania	347	Gas/Oil	Inter/Peak
Ceredo	West Virginia	475	Gas	Peak
Cheswick	Western Pennsylvania	583	Coal	Base
Elrama	Western Pennsylvania	487	Coal	Base
New Castle	Western Pennsylvania	331	Coal/Gas	Base/Peak
Niles	Ohio	246	Coal/Gas	Base/Peak
Shelby County	Illinois	371	Gas	Peak
Total Operating		4,473		

(1) Generating capacity refers to the average of the facilities' summer and winter generating capacities net of auxiliary power.

The following table sets forth information regarding our generation output in the Mid-Continent region by dispatch type, fuel type and capacity factor during 2002 and 2003:

	2002(1)	%	Capacity Factor(2)	2003	%	Capacity Factor(2)
Dispatch Type (GWh)						
Base-load	11,166	96	60%	12,099	99	60%
Intermediate	64	1	3%	4	—	—
Peaking	395	3	2%	111	1	1%
Total	11,625	100%	32%	12,214	100%	31%
Sources of Electric Energy (GWh)						
Coal	11,166	96	60%	12,099	99	60%
Natural gas	457	4	3%	111	1	1%
Oil	2	—	—	4	—	1%
Total	11,625	100%	32%	12,214	100%	31%

(1) Includes generation beginning in February 2002 in connection with our Orion Power acquisition. See note 5 to our consolidated financial statements.

(2) Capacity factor is the ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.

Southeast Region

As of December 31, 2003, we owned, or had an interest in, six power generation facilities with an aggregate net generating capacity of 3,010 MW located in Florida, Mississippi and Texas. Our interest in two of these facilities (1,104 MW) is in the form of a long-term tolling agreement, as described in more detail below. The generating capacity of these facilities consists of approximately 2% of base-load (54 MW), 46% of intermediate (1,387 MW) and 52% of peaking capacity (1,569 MW).

The following table describes the electric power generation facilities we owned or had an interest in the Southeast region of the United States (excluding generation facilities that we retired from service) as of December 31, 2003:

Generation Facilities	Location	Generating Capacity (MW)(1)	Fuel Types Present	Dispatch Types
Operating				
Sabine(2)	Texas (non-ERCOT)	54	Gas	Base
Choctaw	Mississippi	800	Gas	Inter
Indian River	Florida	587	Dual	Inter
Osceola	Florida	465	Dual	Peak
Tolled facilities(3)	Florida	1,104	Dual	Peak
Total Operating		3,010		

(1) Generating capacity refers to the average of the facilities' summer and winter generating capacities net of auxiliary power.

(2) We own a 50% interest in this facility, which has a net generating capacity of 108 MW. An unaffiliated party owns the other 50%. The table includes only our share of the capacity of the facility.

(3) We are party to tolling agreements entitling us to 100% of the capacity of two Florida facilities having 474 MW and 630 MW of net generating capacity, respectively. These tolling agreements have terms expiring in 2007 and 2012, respectively, and are treated as operating leases for accounting purposes.

The following table sets forth information regarding our generation output in the Southeast region by dispatch type, fuel type and capacity factor during 2002 and 2003:

	2002	%	Capacity Factor(1)	2003	%	Capacity Factor(1)
Dispatch Type (GWh)						
Base-load	344	13	73%	333	11	70%
Intermediate	1,152	45	22%	1,246	42	15%
Peaking	1,060	42	11%	1,407	47	10%
Total	2,556	100%	17%	2,986	100%	13%
Sources of Electric Energy (GWh)						
Natural gas	344	13	73%	359	12	11%
Dual	2,212	87	15%	2,627	88	14%
Total	2,556	100%	17%	2,986	100%	13%

(1) Capacity factor is the ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.

West Region

As of December 31, 2003, we owned, or had an interest in, four operating electric power generation facilities with an aggregate net generating capacity of 2,803 MW located in California and Nevada. We have mothballed four units in this region with an aggregate net generating capacity of 824 MW. The operating generating capacity of these facilities consists of approximately 8% of base-load (235 MW), 85% of intermediate (2,384 MW) and 7% of peaking capacity (184 MW). As of December 31, 2003, we were constructing a 591 MW gas-fired, base-load and intermediate generation facility in southern Nevada, which commenced commercial operation in February 2004.

In October 2003, we closed the sale of our 588 MW Desert Basin plant operations to SRP. See note 23 to our consolidated financial statements.

The following table describes the electric power generation facilities we owned or had under construction in the West region (excluding generation facilities that we retired from service) as of December 31, 2003:

Generation Facilities	Location	Generating Capacity (MW) (1)	Fuel Types Present	Dispatch Types
Operating				
Coolwater	California	622	Gas/Dual	Inter
El Dorado(2)	Nevada	235	Gas	Base
Ormond Beach	California	1,516	Gas	Inter
Mandalay	California	430	Gas	Inter
Total Operating		2,803		
Mothballed				
Etiwanda	California	640	Gas	Inter
Mandalay	California	130	Gas	Peak
Ellwood	California	54	Gas	Peak
Total Mothballed		824		
Under Construction				
Bighorn(3)	Nevada	591	Gas	Base/Inter
Total Combined		4,218		

(1) Generating capacity refers to the average of the facilities' summer and winter generating capacities net of auxiliary power.

(2) We own a 50% interest in the El Dorado facility having a net generating capacity of 470 MW. An independent third party owns the other 50%. The table includes our share of the capacity of this facility.

(3) Commenced commercial operation in February 2004.

The following table sets forth information regarding our generation output in the West region by dispatch type, fuel type and capacity factor during 2002 and 2003:

	2002(1)	%	Capacity Factor(2)	2003(1)	%	Capacity Factor(2)
Dispatch Type (GWh)						
Base-load	1,663	21	81%	1,680	30	82%
Intermediate	5,949	77	21%	3,935	70	14%
Peaking	162	2	3%	17	—	1%
Total	7,774	100%	22%	5,632	100%	17%
Sources of Electric Energy (GWh)						
Natural gas	7,592	98	21%	5,590	99	18%
Dual	182	2	14%	42	1	3%
Total	7,774	100%	22%	5,632	100%	17%

(1) Excludes volumes related to our Desert Basin plant, which was sold in October 2003 and is classified as discontinued operations. See note 23 to our consolidated financial statements.

(2) Capacity factor is the ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.

ERCOT Region

As of December 31, 2003, we owned seven power generation facilities with an aggregate net generating capacity of 831 MW located in Texas.

The following table describes the electric power generation facilities we owned in the ERCOT Region as of December 31, 2003:

Generation Facilities	Location	Generating Capacity (MW) (1)	Fuel Types Present	Dispatch Types
Operating				
Channelview	Texas	805	Gas	Base
Landfill gas (2)	Texas	26	Renewable	Base
Total Operating		831		

(1) Generating capacity refers to the average of the facilities' summer and winter generating capacities net of auxiliary power.

(2) Landfill gas represents six small facilities located in the Houston area that collect gas emitted from landfills and convert it into electricity.

The following table sets forth information regarding our generation output in the ERCOT Region by dispatch type, fuel type and capacity factor during 2002 and 2003:

	2002	%	Capacity Factor (1)	2003	%	Capacity Factor (1)
Dispatch Type (GWh)						
Base-load	2,851	100	78%	5,674	100	76%
Total	2,851	100%	78%	5,674	100%	76%
Sources of Electric Energy (GWh)						
Natural gas	2,851	100	78%	5,548	98	79%
Renewables	—	—	—	126	2	55%
Total	2,851	100%	78%	5,674	100%	76%

(1) Capacity factor is the ratio of the actual net electricity generated to the energy that could have been generated at continuous full-power operation during the year.

Commercial Operations

Energy. We sell electric energy, generation capacity and ancillary service products to a variety of power customers including investor-owned utilities, municipalities, cooperatives and other companies that serve end users. We sell these products in hour-ahead, day-ahead, forward bilateral and ISO markets. The following table identifies the principal markets associated with each of our regional generation assets:

Region	Principal Markets
Mid-Atlantic	PJM Market and adjacent power markets (ECAR Market and NY Market)
New York	New York City and upstate New York (hydro)
Mid-Continent	PJM Market, ECAR Market and MAIN Market
Southeast	Florida, Mississippi and Texas (non-ERCOT)
West	California and Nevada
ERCOT	ERCOT

Certain of our principal markets (most notably New York and the PJM Market) have rules that, in certain instances, may impose limits or caps on the price at which we can sell electricity. In addition, the market authorities in certain regions have the authority to compel us to operate our generation facilities in order to maintain the reliability of the local grid system. Under these circumstances, we are entitled to receive a "mitigated price" for electricity dispatched into the system that is intended to enable us to recoup our incremental operating costs plus a designated surcharge.

In addition to standard market products, we also provide full requirements, POLR, and basic generation service contracts. These non-standard contracts afford higher margin opportunities than standard market products; however, they include additional risks that we may not be able to mitigate. These risks are primarily volumetric uncertainty driven by weather and customer switching. For information regarding long-term sales arrangements for electric energy, capacity and ancillary services, see note 14(f) to our consolidated financial statements.

Fuel. To ensure an adequate supply of fuel, we purchase natural gas, coal and fuel oil for our generation plants from a variety of suppliers under daily, monthly and forward contracts. These contracts generally include either index or fixed price provisions. In connection with the operation of our natural gas-fired plants, we also arrange for, schedule and balance natural gas from our suppliers and through transporting pipelines. To perform these functions, and satisfy our electric generation needs, we contract for a variety of transportation arrangements under short-term, long-term, firm and interruptible agreements with pipelines and storage facilities. In spite of our efforts, any given facility may experience supply constraints from time to time.

Risk Management. To manage the risk of our assets we seek to sell energy and purchase fuel on a forward basis through fixed price or tolling contracts. We are required, by policy, to maintain a "one-for-one" balance between the amount of required fuel for each megawatt of power sold off our gas generation assets. We have similar "one-for-one" hedging policies for the hedging of certain pipeline and storage positions.

Although we enter into hedging activities related to our generation facilities, pipelines and storage positions, we do not engage in proprietary trading with respect to power, fuel, emissions or any other energy commodities. With respect to positions taken prior to our decision in 2003 to exit proprietary trading, we are managing such positions solely for the purpose of closing such positions on economical terms.

Regulation

Electricity. 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. The FERC has authorized our generation subsidiaries to sell electricity and certain related services at wholesale under market-based rates. In addition, certain ancillary services are sold at cost-base rates.

Under certain circumstances, the FERC can revoke or limit market-based rate authority. If the FERC revokes or limits market-based rate authority, the affected party would be required to obtain approval from the FERC of cost-based rate schedules in order to make wholesale sales. In addition, the loss of market-based rate authority could subject the affected party to the accounting, record keeping and reporting requirements that the FERC imposes on public utilities with cost-based rate schedules.

In November 2003, the FERC issued new rules intended to prevent market abuse. The new rules address market manipulation and other abusive practices. Under the rules, parties found to have engaged in prohibited behavior are subject to disgorgement of unjust profits and possible revocation of their market-based rate authority.

The FERC has issued a notice of proposed rules intended to standardize electricity markets and eliminate discrimination in transmission service by requiring that all users of the transmission grid take service pursuant to the same terms and conditions of service, thus eliminating certain preferences enjoyed

by classes of users. The new rules would require transmission-owning public utilities to join an ISO or RTO. In addition, the FERC seeks to establish day-ahead and real-time electric energy and ancillary service markets modeled after the energy markets that currently exist in the northeastern United States. The rules contemplate the regional adoption of resource adequacy measures and regional price mitigation measures. It is not possible for us at this time to predict the timing of the implementation of these rules or their ultimate impact on our business.

Gas Activities. The FERC has issued a blanket certificate permitting us to sell natural gas in interstate commerce in connection with the management of our natural gas positions.

Hydroelectric Facilities. We operate our hydroelectric generation facilities pursuant to FERC licenses. These licenses, which periodically must be renewed, typically include conditions regarding the operation of the facility.

SEC. 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 PUHCA as an exempt wholesale generator. Our electric generation subsidiaries either have received determinations of exempt wholesale generator status from the FERC or are companies that own or operate qualifying facilities that are exempt from PUHCA. If any of our subsidiaries lose their exempt wholesale generator status or qualifying facility status, we would have to restructure our organization or risk being subjected to further regulation by the SEC.

Competition

For a discussion of competitive factors affecting our wholesale energy segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors" in Item 7 of this report.

Other Operations

Our other operations business segment includes primarily unallocated corporate costs and our minor equity and other investments. As of December 31, 2003, the net book value of these investments was $32 million. Our activities with respect to these investments are limited to managing and, in some cases, liquidating our existing portfolio. We have no plans to expand this business. For additional information regarding this segment, see note 21 to our consolidated financial statements.

Environmental Matters

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 compounds into the 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. Environmental regulations affecting us include, but are not limited to:

- The Clean Air Act and the 1990 amendments to the Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and fine particulate matter. Owners and/or operators of air emissions sources are responsible for obtaining permits, compliance and reporting.
- The Federal Water Pollution Control Act, which requires permits for facilities that discharge treated wastewater into the environment.
- CERCLA, which can require any individual or entity that may have owned or operated a disposal site, as well as transporters or generators of hazardous wastes sent to such site, to share in remediation costs.

- The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime.
- The National Environmental Policy Act, which requires consideration of potential environmental impacts by federal agencies in their decisions, including siting approvals.
- The FERC, which regulates the approval and re-licensing of hydroelectric facilities.

In order to comply with these requirements, we will, as necessary, spend substantial funds to construct, modify and retrofit equipment, and clean up or decommission disposal or fuel storage areas and other locations as necessary. We anticipate spending approximately $178 million from 2004 through 2008 for environmental compliance of which $16 million is for remediation. For more information on environmental matters involving us, including possible liability and capital costs, see note 15(a) to our consolidated financial statements.

Air Quality Matters

The Federal Clean Air Act requires the EPA to define standards for air quality that are protective of public health. As a result of setting these standards, the EPA has implemented a number of emission control programs that affect industrial sources including power plants. In addition, the 1990 Amendments to the Clean Air Act directed EPA to implement programs designed to control acidic deposition (acid rain), improve visibility in the United States' pristine areas and national parks (regional haze), and reduce emissions of hazardous air pollutants.

Regulation of NO_x and SO_2 Emissions

As a result of the mandates of the Clean Air Act, the EPA has implemented programs limiting emissions of NO_x and SO_2, both of which are compounds that result from the combustion of fossil fuels. NO_x is a precursor to the formation of ozone, acid rain, fine particulate matter, and regional haze. SO_2 is a precursor to the formation of acid rain, fine particulate matter, and regional haze. In addition to regulations already implemented, the EPA in December 2003 proposed a new regulation to control emissions of NO_x and SO_2 on a broad scale. This new proposed regulation is referred to as the Interstate Air Quality Rule, and will affect our power generating facilities in the eastern United States and Texas.

The Interstate Air Quality Rule would require reductions in NO_x and SO_2 beyond levels already required in existing federal programs in 29 states in the eastern United States. The proposed rules will require reductions of NO_x and SO_2 in two phases. Although the final form of the proposed regulations is not yet known, the first phase, which takes effect in 2010, would require approximately a 50% reduction in SO_2 and NO_x emissions on an annual basis. The second phase, which would take effect in 2015, would require approximately a 70% reduction in SO_2 and NO_x on an annual basis. These reductions would be achieved through a trading program, allowing reductions to be made at the most economical locations, and not requiring reductions on a facility-by-facility basis. The proposed rules would affect primarily our facilities in the eastern United States (particularly the coal-fired facilities) and Texas. We are unable at this time to estimate the potential impact on the future operations of our generation facilities.

Regulation of Emissions of Mercury and other Hazardous Air Pollutants

In December 2003, the EPA also proposed two regulations to control emissions of mercury from coal-fired power plants in the United States. Only one of these two regulations will ultimately be adopted in December 2004. The MACT standard would require reductions on a facility-by-facility basis regardless of cost. The MACT rule would require reductions to be achieved by 2008. The other rule, referred to as the cap-and-trade rule, would effect the emission reductions on a national scale through a trading program, allowing reductions to be made at the most economical locations, and not requiring reductions on a facility-by-facility basis. Although the final form of these proposed regulations is not yet known, the MACT standard would require a reduction of about 30% from each of our coal fired facilities, which

would require the installation of control equipment. The cap-and-trade rule would require larger reductions, but may be more economical because it allows trading of emissions among facilities. Like the Interstate Air Quality Rule, the mercury cap-and-trade rule would be accomplished in two phases, in 2010 and 2018, with reduction levels set at approximately 50% and 70%, respectively. If the cap-and-trade rule were ultimately adopted, our approach would be to balance capital expenditures for controls and reliance on allowance markets to achieve compliance. We are unable at this time to estimate the potential impact on the future operations of our generation facilities.

In addition to mercury control from coal-fired boilers, the MACT rule, if adopted, would require the control of nickel emissions from oil-fired facilities. While the final form of these provisions is uncertain, we do not expect this provision of the MACT to have a material impact on our operations since only a small number of our facilities are oil-fired.

The EPA has also proposed or issued MACT standards for sources other than boilers used for power generation. The MACT rule for combustion turbines was issued in August 2003 and there is no material impact on existing facilities. We expect the MACT rulemaking for engines and industrial boilers to be finalized in early 2004. Based on the current form of the proposed rules for these source types, we do not anticipate that the rules, if adopted, will have a material impact on our operations.

Clear Skies Act

In February 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, nitrogen oxide and mercury. If approved by the United States Congress, this program would entail a market-based approach using emission allowances; compliance with emission limits would be phased in over a period from 2008 to 2018. The Clear Skies Initiative is similar to the proposed Interstate Air Quality rule and mercury MACT/cap-and-trade rule.

Air Quality Enforcement Issues

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, eight of our coal-fired facilities have received requests for information related to work activities conducted at those sites. 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 anticipated as a result of proposed regulations, and result in the imposition of penalties.

The New Jersey Department of Environmental Protection has requested a copy of all correspondence relating to one of the eight stations from the EPA. The EPA has also agreed to provide information relating to the New Source Review investigations discussed above to the New York state attorney general's office and the Pennsylvania Department of Environmental Protection.

Greenhouse Gas Emissions

The Kyoto Protocol, which may become effective in 2004, if ratified by a sufficient number of nations, would require ratifying nations to achieve substantial reductions of CO_2 and certain other greenhouse gases between 2008 and 2012. Although the current United States government has indicated that it does not intend to ratify the treaty at this time, any future limitations on power plant carbon dioxide emissions could have a material impact on all fossil fuel fired facilities, including those belonging to us.

There continues to be a debate within the United States over the direction of domestic climate change policy. The United States Congress is currently considering several bills that would impose

mandatory limitation of CO_2 emissions for the domestic power generation sector, and several other states, primarily in the northeastern United States, are considering state-specific or regional legislation initiatives to stimulate CO_2 emission reductions in the electric utility industry. The specific impact will depend upon the form of emissions-related legislation or regulations ultimately adopted by the federal government or states in which our facilities are located.

In recent years, we have instituted or participated in numerous proactive projects and programs that go beyond regulatory compliance requirements in an effort to reduce and remove greenhouse gas emissions. These effective actions include:

- Participation in the Power Partners Program, designed to encourage and facilitate industry actions to reduce greenhouse gas intensity as outlined in President Bush's voluntary global climate change initiative;
- Participation in PowerTree, an entity comprised of a diverse group of power generators that endeavors to remove CO_2 emissions through large-scale reforestation projects;
- Independent establishment of a 540-acre arboreal preserve in east Texas to remove emissions;
- Operation of renewable energy facilities, including, hydro-electric and landfill gas-to-energy facilities; and
- Recent retirement of CO_2 producing facilities in California, New Jersey and Pennsylvania.

Water Quality Matters

The EPA and states periodically revise water quality criteria and initiate total maximum daily load determinations under the Clean Water Act. These actions may result in more stringent wastewater discharge limitations for our power plants and the need to install additional water treatment systems or control measures.

On February 16, 2004, the EPA signed final regulations relating to the design and operation of cooling water intake structures at existing power plants. While there may be significant compliance costs associated with this rule, site-specific evaluation of compliance alternatives will be required to determine the magnitude of those potential costs.

FERC Matters

In the course of the FERC licensing proceedings various agencies have requested increased flow rates downstream of our hydroelectric dams in order to enhance fish habitats and for other purposes. The FERC has imposed conditions in the new licenses to increase such flow rates and we expect that the FERC will also impose similar conditions in the licenses for which applications remain pending. Increased flow rates may affect revenues for these facilities due to the loss of use of water for power generation. We do not, however, expect such lost revenues to be material to the economic viability of such facilities.

Other

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. We have planned for the proper management, abatement and disposal of asbestos and lead-based paint at our facilities in our financial planning.

Under CERCLA and similar state laws, owners and operators of facilities from or at 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 the act that would have a material adverse effect on our results of operations, financial position or cash flows.

For information regarding plant remediation activities, see note 15(a) to our consolidated financial statements.

Employees

As of December 31, 2003, we had 5,293 full-time employees. Of these employees, 1,434 are covered by collective bargaining agreements. The collective bargaining agreements expire on various dates until April 2008. In 2004, three of the collective bargaining agreements applicable to certain employees associated with our facilities in the Mid-Atlantic, New York and Mid-Continent regions are expected to expire. The following table sets forth the number of our employees by business segment as of December 31, 2003:

Segment	Number
Retail energy	1,810
Wholesale energy	2,917
Other operations	566
Total	5,293

Executive Officers

The following table lists our executive officers:

Name	Age(1)	Present Position
Joel V. Staff	60	Chairman and Chief Executive Officer
Robert W. Harvey	48	Executive Vice President, Power Generation and Supply
Mark M. Jacobs	41	Executive Vice President and Chief Financial Officer
Jerry J. Langdon	52	Executive Vice President, Public and Regulatory Affairs and Corporate Compliance Officer
Karen Dyson	46	Senior Vice President, Human Resources and Administration
Michael L. Jines	45	Senior Vice President, General Counsel and Corporate Secretary
Suzanne L. Kupiec	37	Senior Vice President, Risk and Structuring
Brian Landrum	42	Senior Vice President, Customer Operations and Information Technology
James B. Robb	43	Senior Vice President, Retail Marketing
Thomas C. Livengood	48	Vice President and Controller

(1) Age is as of March 1, 2004.

Joel V. Staff has served as our Chairman and Chief Executive Officer since April 2003. He has served as a Director since October 2002. From May 2001 to May 2002, he was Executive Chairman of National-Oilwell, Inc. From July 1993 to May 2001, Mr. Staff served as Chairman, President and Chief Executive Officer of National-Oilwell, Inc. He also serves on the board of directors of National-Oilwell, Inc. and Ensco International, Incorporated.

Robert W. Harvey has served as our Executive Vice President, Power Generation and Supply since January 2004. He served as our Executive Vice President and Group President, Wholesale from May 2003 to January 2004. He served as our Executive Vice President and Group President, Retail from January 2002 to May 2003. Mr. Harvey served as Vice Chairman of CenterPoint from June 1999 until the Distribution. From 1982 to June 1999, Mr. Harvey was with the Houston office of McKinsey & Company. He was a director (senior partner) of the firm and was the leader of the firm's North American electric power and natural gas practice.

Mark M. Jacobs has served as our Executive Vice President and Chief Financial Officer since the Distribution. He served as Executive Vice President and Chief Financial Officer of CenterPoint from July 2002 until the Distribution. Mr. Jacobs was employed by Goldman, Sachs & Co. from 1989 to 2002. He was a Managing Director in the firm's Natural Resources Group.

Jerry J. Langdon has served as our Executive Vice President, Public and Regulatory Affairs and Corporate Compliance Officer since January 2004. He served as our Executive Vice President and Chief Administrative Officer from May 2003 to January 2004. Prior to joining Reliant Resources, Mr. Langdon served as President of EPGT Texas Pipeline, L.P. from June 2001 until May 2003. He served as the Managing Partner and Chief Operating Officer of CARLANG Partners, L.P.

Karen Dyson has served as our Senior Vice President, Human Resources and Administration since December 2003. She served as Vice President, Human Resources from February 2003 to December 2003, Vice President, Administration, Wholesale Group from October 1998 to February 2003 and Vice President, Planning and Procurement for the former Reliant Energy Trading and Transportation from February 1996 to October 1998.

Michael L. Jines has served as our Senior Vice President, General Counsel and Corporate Secretary since May 2003. He served as our Deputy General Counsel and Senior Vice President and General Counsel, Wholesale Group from March 2002 to May 2003. Mr. Jines served as Deputy General Counsel of Reliant Energy and Senior Vice President and General Counsel of our Wholesale Group until the Distribution.

Suzanne L. Kupiec has served as our Senior Vice President, Risk and Structuring since January 2004. She served as our Vice President and Chief Risk and Corporate Compliance Officer from June 2003 to January 2004. Prior to joining Reliant Resources, Ms. Kupiec was a partner at Ernst & Young, LLP, leading the firm's Energy Trading and Risk Management Practice serving both audit and advisory service clients. Ms. Kupiec was a firm specialist in the use of financial instruments and complex derivatives for the energy industry.

Brian Landrum has served as our Senior Vice President, Customer Operations and Information Technology since January 2004. He was our President, Reliant Energy Retail Services from June 2003 to January 2004, Senior Vice President, Retail Operations from August 2001 to May 2003, and Vice President, Internet and Ebusiness from November 1999 to August 2001. Before joining Reliant Resources, Mr. Landrum was employed at Compaq Computer Corporation as General Manager of its Worldwide Commercial Displays business unit.

James B. Robb has served as our Senior Vice President, Retail Marketing since January 2004. He served as our Senior Vice President, Performance Management from November 2002 to January 2004. Prior to joining Reliant Resources, Mr. Robb was a partner with McKinsey & Company in San Francisco, California and Seattle, Washington, focusing on service to energy and natural resources clients on issues related to corporate and business unit strategy and fundamental performance improvement. He led McKinsey & Company's West Coast Energy and Resources Practice from 1998 until 2002.

Thomas C. Livengood has served as our Vice President and Controller since August 2002. From 1996 to August 2002, he served as Executive Vice President and Chief Financial Officer of Carriage Services, Inc.

Available Information

Our executive offices are located at 1000 Main, Houston, Texas 77002 (telephone number is 713-497-7000).

We make available free of charge on our website (http://www.reliantresources.com):

- our corporate governance guidelines;
- our audit committee, compensation committee, and nominating and corporate governance committee charters;
- our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports; and
- our business ethics policy and any amendments to, or waivers from, a provision of our policy that applies to our principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions.

Additionally, you may request a copy of any of these items, at no cost, by writing or telephoning us at the address or number above and requesting the investor relations department. Annual reports, quarterly reports and current reports are made available on our website as soon as reasonably practicable after we file such reports with, or furnish them, to the SEC.

Stockholder Communications with the Board of Directors

We have established several means for stockholders or others to communicate their concerns to the Board of Directors.

- If the concern relates to our financial statements, accounting practices or internal controls, the concern should be submitted in writing to the Chairman of the Audit Committee in care of the following address:

  Reliant Resources Compliance Hotline
  P.M.B. 3767
  Pinkerton Compliance Services
  13950 Ballantyne Corporate Place
  Charlotte, North Carolina 28277

- If the concern relates to our governance practices, business ethics or corporate conduct, the concern may be submitted in writing to the Chairman of the Nominating & Governance Committee in care of our Corporate Secretary at 1000 Main, Houston, Texas 77002. If the stockholder is unsure as to which category his or her concern relates, he or she may communicate it to any one of the independent directors in care of the Corporate Secretary.

- Our "whistleblower" policy prohibits us or any of our employees from retaliating or taking any adverse action against anyone for raising a concern. We have established and published on our website mailing and e-mail addresses and a 24-hour, toll-free telephone hotline for receiving complaints regarding accounting issues from employees and others. The mailing address is:

  Corporate Compliance Officer
  Reliant Resources, Inc.
  P.O. Box 1384
  Houston, Texas 77251-1384

The email address is: **CorpComOfficer@reliant.com.**

Item 2. ***Properties.***

Our corporate offices occupy approximately 520,000 square feet of leased office space in Houston, Texas. Our lease expires in 2018, subject to two five-year renewal options.

In addition to our corporate offices, we lease or own various real property and facilities relating to our generation assets, retail operations and retail activities. Our principal generation facilities are generally described under "Our Business — Wholesale Energy" in Item 1 of this report. 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.

Item 3. ***Legal Proceedings.***

For a description of certain legal and regulatory proceedings affecting us, see note 15 to our consolidated financial statements.

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

No matters were submitted to a vote of our security holders during the fourth quarter of the year ended December 31, 2003.

PART II

Item 5. ***Market for Our Common Equity and Related Stockholder Matters.***

As of March 1, 2004, our common stock was held by approximately 50,426 stockholders of record. Our common stock is listed on the New York Stock Exchange and is traded under the symbol "RRI." 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*:

	Market Price	
	High	**Low**
2002		
First Quarter	$17.45	$9.50
Second Quarter	$17.16	$7.28
Third Quarter	$ 8.95	$1.66
Fourth Quarter	$ 3.23	$0.99
2003		
First Quarter	$ 5.70	$2.25
Second Quarter	$ 7.05	$3.82
Third Quarter	$ 6.38	$3.39
Fourth Quarter	$ 7.54	$4.63

The closing market price of our common stock on December 31, 2003 was $7.36 per share.

We have not paid or declared any dividends since our formation and do not currently intend to pay or declare any dividends in the immediate future. Any future dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable contractual restrictions, including the restriction on our ability to pay dividends under our March 2003 credit facilities and our senior secured notes and other factors that our board of directors considers relevant.

Sales of Unregistered Securities. In June and July 2003, we sold $275 million of our convertible senior subordinated notes in a private placement pursuant to Rule 144A and Regulation S to qualified

institutional buyers. The primary underwriters were Banc of America Securities LLC, Deutsche Bank Securities Inc. and Goldman Sachs & Co. We received net proceeds of $266 million, which we ultimately used to prepay debt under our March 2003 credit facilities. In December 2003, we registered these convertible senior subordinated notes and the common stock issuable upon conversion in order that the original holders may transfer such securities. In July 2003, we sold $1.1 billion of our senior secured notes in a private placement pursuant to Rule 144A and Regulation S to qualified institutional buyers. The primary underwriters were Banc of America Securities LLC, Deutsche Bank Securities Inc., Goldman Sachs & Co. and Barclays Capital Inc. We received net proceeds of $1.056 billion, which we used to prepay $1.056 billion of senior secured term loans under our March 2003 credit facilities. In January 2004, we exchanged these senior secured notes for registered notes that were identical in all material respects, but did not contain terms restricting their transfer. See note 9 to our consolidated financial statements.

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

The following tables present our selected consolidated financial data for 1999 through 2003. The data set forth below should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations," our historical consolidated financial statements and the notes to those statements included in this report. The historical financial information may not be indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone entity prior to September 30, 2002, when CenterPoint ceased to be our parent company. See note 1 to our consolidated financial statements. The financial data for 1999 and 2000 are derived from the consolidated historical financial statements of CenterPoint.

	Year Ended December 31,				
	1999 (1)	2000 (1)	2001 (1) (2)	2002 (1) (2) (3) (4)	2003 (1) (2) (4) (5) (6)
	(In millions, except per share amount)				
Income Statement Data:					
Revenues	$601	$2,732	$5,499	$10,588	$11,049
Trading margins	88	198	378	288	(49)
Total	689	2,930	5,877	10,876	11,000
Expenses:					
Fuel and cost of gas sold	293	911	1,576	1,082	1,414
Purchased power	149	926	2,498	7,421	7,031
Accrual for payment to CenterPoint	—	—	—	128	47
Operation and maintenance	128	336	461	785	865
General, administrative and development	94	270	471	629	552
Wholesale energy goodwill impairment	—	—	—	—	985
Depreciation and amortization	23	118	170	368	419
Total	687	2,561	5,176	10,413	11,313
Operating income (loss)	2	369	701	463	(313)
Other income (expense):					
Gains (losses) from investments	14	(22)	23	(23)	2
(Loss) income of equity investments	(1)	43	7	18	(2)
Gain on sale of development project	—	18	—	—	—
Loss on sale of receivables	—	—	—	(10)	(37)
Other, net	1	—	2	15	9
Interest expense	—	(7)	(16)	(267)	(516)
Interest income	1	16	22	28	35
Interest (expense) income — affiliated companies, net	(6)	(172)	12	5	—
Total other income (expense)	9	(124)	50	(234)	(509)
Income (loss) from continuing operations before income taxes	11	245	751	229	(822)
Income tax expense	6	102	290	106	80
Income (loss) from continuing operations	5	143	461	123	(902)
Income (loss) from discontinued operations before income taxes	15	73	83	(341)	(310)
Income tax (benefit) expense	(4)	(7)	(16)	108	106
Income (loss) from discontinued operations	19	80	99	(449)	(416)
Income (loss) before cumulative effect of accounting changes	24	223	560	(326)	(1,318)
Cumulative effect of accounting changes, net of tax	—	—	3	(234)	(24)
Net income (loss)	$ 24	$ 223	$ 563	$ (560)	$(1,342)

	Year Ended December 31,				
	1999 (1)	2000 (1)	2001 (1) (2)	2002 (1) (2) (3) (4)	2003 (1) (2) (4) (5)
	(In millions, except per share amount)				
Basic Earnings (Loss) per Share:					
Income (loss) from continuing operations			$1.66	$ 0.43	$(3.07)
Income (loss) from discontinued operations, net of tax			0.36	(1.55)	(1.42)
Income (loss) before cumulative effect of accounting changes			2.02	(1.12)	(4.49)
Cumulative effect of accounting changes, net of tax			0.01	(0.81)	(0.08)
Net income (loss)			$2.03	$(1.93)	$(4.57)
Diluted Earnings (Loss) per Share:					
Income (loss) from continuing operations			$1.66	$ 0.42	$(3.07)
Income (loss) from discontinued operations, net of tax			0.36	(1.54)	(1.42)
Income (loss) before cumulative effect of accounting changes			2.02	(1.12)	(4.49)
Cumulative effect of accounting changes, net of tax			0.01	(0.80)	(0.08)
Net income (loss)			$2.03	$(1.92)	$(4.57)

	Year Ended December 31,				
	1999 (1)	2000 (1)	2001 (1)	2002 (1)	2003 (1)
	(In millions, except operating data)				
Statement of Cash Flow Data:					
Cash flows from operating activities	$ 38	$ 335	$ (152)	$ 519	$ 869
Cash flows from investing activities	(1,406)	(3,013)	(838)	(3,486)	1,042
Cash flows from financing activities	1,408	2,721	1,000	3,981	(2,888)
Operating Data:					
Retail electricity sales (GWh)	—	—	—	60,736	63,999
Power generation data(7):					
Wholesale power sales volumes (GWh)(8)	10,204	39,300	63,298	130,172	116,223
Wholesale net power generation volumes (GWh)	6,412	21,379	25,808	43,431	45,522
Trading data:					
Trading power sales volumes (GWh)	128,266	125,971	222,907	306,425	81,674
Trading natural gas sales volumes (Bcf)	1,481	2,273	3,265	3,449	891

	December 31,				
	1999 (1)	2000 (1)	2001 (1)(2)	2002 (1)(2)(3)(4)	2003 (1)(2)(4)(5)(9)
	(In millions)				
Balance Sheet Data:					
Property, plant and equipment, net	$ 592	$2,217	$2,796	$6,991	$8,527
Total assets	5,624	13,475	11,726	17,220	13,308
Current portion of long-term debt and short-term borrowings	20	—	94	820	431
Long-term debt to third parties	49	260	295	6,009	5,709
Accounts and notes (payable) receivable — affiliated companies, net	(1,333)	(1,967)	445	—	—
Stockholders' equity	741	2,345	5,984	5,653	4,372

(1) Our results of operations include the results of the following acquisitions, all of which were accounted for using the purchase method of accounting, from their respective acquisition dates: a generating facility in Florida acquired in October 1999, the REMA acquisition that occurred in May 2000 and the Orion Power acquisition that occurred in February 2002. See note 5 to our consolidated financial statements for further information about the Orion Power acquisition. In December 2003, we sold our European energy operations. In the first quarter of 2003, we began to report the results of our European energy operations as discontinued operations in accordance with SFAS No. 144 and accordingly, reclassified amounts from prior periods. See note 22 to our consolidated financial statements. In October 2003, we sold our Desert Basin plant operations and in accordance with SFAS No. 144, effective July 2003, we began to report the results of our Desert Basin plant operations as discontinued operations and accordingly, reclassified amounts from prior periods. See note 23 to our consolidated financial statements.

(2) Effective January 1, 2001, we adopted SFAS No. 133 which established accounting and reporting standards for derivative instruments. See notes 2(d) and 7 to our consolidated financial statements.

(3) During the third quarter of 2002, we completed the transitional impairment test for the adoption of SFAS No. 142 on our consolidated financial statements, including the review of goodwill for impairment as of January 1, 2002. Based on this impairment test, we recorded an impairment of our European energy segment's goodwill of $234 million, net of tax, as a cumulative effect of accounting change. See note 6 to our consolidated financial statements.

(4) We adopted EITF No. 02-03 effective January 1, 2003, which affected our accounting for electricity sales to large commercial, industrial and institutional customers under executed contracts and our accounting for trading and hedging activities. It also impacted these contracts executed after October 25, 2002 in 2002. See note 2(d) to our consolidated financial statements.

(5) During the third quarter of 2003, we performed a goodwill impairment analysis of our wholesale energy reporting unit and recognized an impairment charge of $985 million. See note 6 to our consolidated financial statements.

(6) In July 2003, the EITF issued EITF No. 03-11, which became effective October 1, 2003. At that time, we began reporting prospectively the settlement of sales and purchases of fuel and purchased power related to our non-trading commodity derivative

activities that were not physically delivered on a net basis in our results of operations based on the item hedged pursuant to EITF No. 03-11. This resulted in decreased revenues and decreased fuel and cost of gas sold and purchased power of $834 million for the fourth quarter of 2003. We believe the application of EITF No. 03-11 will continue to result in a significant amount of our non-trading commodity derivative activities being reported on a net basis prospectively that were previously reported on a gross basis. We did not reclassify amounts for periods prior to October 1, 2003. See note 2(d) to our consolidated financial statements.

(7) These amounts exclude volumes associated with our Desert Basin plant operations and our European energy operations, which are classified as discontinued operations.

(8) Includes physically delivered volumes, physical transactions that are settled prior to delivery and non-trading derivative activity related to our power generation portfolio.

(9) We adopted FIN No. 46 on January 1, 2003, as it relates to our variable interests in three power generation projects that were being constructed by off-balance sheet entities under construction agency agreements, which pursuant to this guidance required consolidation upon adoption. As a result, as of January 1, 2003, we increased our property, plant and equipment by $1.3 billion and increased our secured debt obligations by $1.3 billion. See notes 2(c), 9(a) and 14(b) to our consolidated financial statements.

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

Overview

In this section, we discuss our results of operations on a consolidated basis and on a segment basis for each of our financial reporting segments. Our segments include retail energy, wholesale energy and other operations. For additional information about our segments, see "Business" in Item 1 of this report and note 21 to our consolidated financial statements.

We have three key objectives and strategies:

- We seek to be a highly efficient, customer-focused competitor. To achieve this objective, we intend to (a) effect significant reductions in our overhead and operating costs, (b) implement process efficiencies and reduce costs, (c) mothball/retire marginal assets and (d) establish an environment conducive to the development of a highly focused and motivated team.
- We intend to strengthen our balance sheet by (a) enhancing our profitability, (b) divesting non-strategic assets and (c) accessing the capital markets to repay bank debt with the proceeds from offerings of fixed income or equity securities.
- In order to capitalize on our competitive advantages, we intend to focus on regions where we believe the rules support competitive markets, to link our generation assets to customer loads and to capitalize on our unique retail skill set.

Our ability to achieve our strategies and objectives are subject to a number of factors some of which we may not be able to control. See "Cautionary Statement Regarding Forward-Looking Information" and "— Risk Factors."

In 2003 and 2004, we have taken a number of actions intended to reduce our debt, strengthen our balance sheet and allow us to focus on our core business — generating, supplying and marketing electricity to customers.

- In March 2003, we discontinued our proprietary trading activities (see note 7(b) to our consolidated financial statements).
- In March 2003, we refinanced $5.9 billion of bank credit facilities with new facilities that mature in approximately four years (see note 9(a) to our consolidated financial statements).
- In June and July 2003, we issued $1.1 billion in senior secured notes and $275 million in convertible senior subordinated notes and used the net proceeds of the senior secured notes to prepay debt thereby satisfying the only mandatory principal payment required under our March 2003 credit facilities prior to maturity.

- In August 2003, we reviewed our internal cost structure and identified $140 million of annualized savings opportunities of which $25 million was realized in 2003 and $125 million is expected to be realized in 2004.

- As part of our ongoing evaluation of our wholesale energy business, we (a) recognized an impairment of $985 million of goodwill in this segment, (b) retired 489 MW of plant assets and mothballed 824 MW of plant assets in 2003 that no longer made economic sense to currently operate and (c) sold our 588 MW Desert Basin plant operations and recorded an after-tax loss on the sale of $75 million (see notes 6 and 23 to our consolidated financial statements). In February 2004, we announced our plans to mothball and/or retire an additional 727 MW from certain peaking plants and units that serve the PJM Market subject to a review of certain reliability issues with regulators.

- We (a) settled investigations by the CFTC relating to certain trading and price reporting issues, (b) settled all inquiries, investigations and proceedings instituted by the FERC involving us in connection with the FERC's ongoing review of western energy markets (except the pending FERC refund proceeding) and (c) settled an investigation by the SEC concerning allegations of violations of federal securities law. See note 15 to our consolidated financial statements.

- In December 2003, we completed the sale of our European energy operations (and recognized a loss on sale of $310 million) in order to reduce debt and allow us to focus exclusively on our United States operations (see note 22 to our consolidated financial statements).

- In December 2003, we finalized a second amendment to our March 2003 credit facilities. In connection with the amendment, we used $917 million that had accumulated in an escrow account, including (a) the net sale proceeds of our Desert Basin plant, (b) a portion of the net sale proceeds of our European energy operations and (c) the net proceeds of our convertible senior subordinated notes to prepay debt under our March 2003 credit facilities. The amendment will give us greater flexibility to purchase selected generating assets to support our retail business in Texas. In connection with this amendment, we also canceled our $300 million senior priority facility. See note 9(a) to our consolidated financial statements.

- In January 2004, we made the decision to not exercise our option to purchase CenterPoint's 81% ownership interest in Texas Genco in favor of pursuing a strategy of contracting for a significant portion of our retail energy supply requirements, and over time, pursuing potential acquisitions of individual generation assets.

- Consistent with our business objectives and strategies, in February 2004 we announced that we intend to reduce our net debt-to-adjusted EBITDA ratio significantly by the end of 2006. Consistent with this plan, we have targeted an additional $200 million in cost reductions. These reductions are in addition to our $140 million cost reduction plan discussed above.

Although we have taken a number of actions in 2003 and early 2004 to restructure our business to meet current market conditions, we continue to face a number of near and long-term challenges. The operations of our wholesale energy segment continue to be negatively affected by depressed market conditions. These, and other factors, are discussed in more detail in "— Risk Factors" and other sections below.

As part of our efforts to simplify the corporate structure to reflect a single operating company, we are evaluating a possible change in our reportable segments in future reporting periods.

Consolidated Results of Operations

2003 Compared to 2002

Net Loss. We reported $1.3 billion consolidated net loss, or $4.57 loss per share, for 2003 compared to $560 million consolidated net loss, or $1.92 loss per diluted share, for 2002. The $782 million increase in net loss is detailed as follows (in millions):

Wholesale energy segment EBIT	$ 964
Interest expense	249
Retail energy segment EBIT	(101)
Other operations segment EBIT	(59)
Discontinued operations, net of tax	(33)[1]
Income tax expense	(26)
Interest income	(7)
Other, net	5
Net increase before cumulative effect of accounting changes	992
Cumulative effect of accounting changes in 2003, net of tax	24[2]
Cumulative effect of accounting change in 2002, net of tax	(234)[3]
Net increase in loss	$ 782

(1) See notes 22 and 23 to our consolidated financial statements.

(2) See notes 2(c), 2(d) and 2(q) to our consolidated financial statements.

(3) See note 6 to our consolidated financial statements.

EBIT. For an explanation of changes in EBIT, see "— EBIT by Business Segment."

Interest Expense. We incurred $516 million of interest expense to third parties during 2003 compared to $267 million in 2002. The $249 million increase in interest expense to third parties is detailed as follows (in millions):

Interest expense on third-party debt	$166[1]
Write-off of deferred financing costs	55[2]
Amortization of deferred financing costs	47[2]
Bank and facility fees	34
Unrealized loss on de-designated interest rate caps	9[3]
Amortization of warrants	7[4]
Amortization of adjustments to fair value of interest rate swaps	7[1]
Capitalized interest	(57)[5]
Reclass from other comprehensive loss for terminated interest rate swaps	(16)[3]
Offsets to interest expense for amortization of adjustments to fair value of debt	(3)[1]
Net increase in expense	$249

(1) See note 9 to our consolidated financial statements.

(2) See note 2(r) to our consolidated financial statements.

(3) See note 9(c) to our consolidated financial statements.

(4) See note 9(b) to our consolidated financial statements.

(5) See note 2(i) to our consolidated financial statements.

Interest Income. We recognized interest income from third parties of $35 million for 2003 as compared to $28 million for 2002. The increase is primarily due to interest income of $13 million recorded during 2003 compared to $5 million recorded during 2002, recognized on receivables related to energy sales in California (see note 15(b) to our consolidated financial statements).

Income Tax Expense. During 2002, our effective tax rate was 46.2%. Our effective tax rate for 2003 is not meaningful due to the goodwill impairment charge of $985 million, which is non-deductible for income tax purposes. Our reconciling items from the federal statutory rate of 35% to the effective tax rate totaled $26 million for 2002. These items primarily related to state income taxes and an increase in valuation allowances primarily due to the impairment of certain venture capital investments. Our reconciling items from the federal statutory rate of 35% to the effective tax rate totaled $23 million, excluding the goodwill impairment charge, for 2003. These items primarily related to state income taxes, tax reserves, valuation allowances related to Canadian operating losses and revisions of estimates for taxes accrued in prior periods. See note 13 to our consolidated financial statements.

2002 Compared to 2001

Net Loss. We reported $560 million consolidated net loss, or $1.92 loss per diluted share, for 2002 compared to $563 million consolidated net income, or $2.03 earnings per share, for 2001. The $1.1 billion decrease in net income is detailed as follows (in millions):

Wholesale energy segment EBIT	$ (883)
Discontinued operations, net of tax	(548) [1]
Interest expense	(251)
Retail energy segment EBIT	533
Income tax benefit/expense	184
Other operations segment EBIT	80
Interest income	6
Other, net	(7)
Net decrease before cumulative effect of accounting changes	(886)
Cumulative effect of accounting change in 2002, net of tax	(234) [2]
Cumulative effect of accounting change in 2001, net of tax	(3) [3]
Net decrease in income	$(1,123)

(1) See notes 22 and 23 to our consolidated financial statements.

(2) See note 6 to our consolidated financial statements.

(3) See notes 2(d) and 7 to our consolidated financial statements.

EBIT. For an explanation of changes in EBIT, see "— EBIT by Business Segment."

Interest Expense. We incurred $267 million of interest expense to third parties during 2002 compared to $16 million in 2001. The $251 million increase in interest expense to third parties is detailed as follows (in millions):

Interest expense on debt related to Orion Power acquisition, including amortization of adjustments	$207[1]
Other interest expense on third-party debt	24[2]
Reclass from other comprehensive loss for terminated interest rate swaps in 2002	16[2]
Capitalized interest on third-party debt	11[3]
Bank and facility fees	4
Amortization of deferred financing costs	2
Interest on margin deposits	(13)
Net increase in expense	$251

(1) See notes 5 and 9 to our consolidated financial statements.

(2) See note 9 to our consolidated financial statements.

(3) See note 2(i) to our consolidated financial statements.

Interest Income. We recognized interest income from third parties of $28 million for 2002 compared to $22 million for 2001. The increase is primarily due to interest income of $5 million recorded during 2002, recognized on receivables related to energy sales in California (see note 15(b) to our consolidated financial statements).

Income Tax Expense. During 2001 and 2002, our effective tax rate was 38.7% and 46.2%, respectively. Our reconciling items from the federal statutory rate of 35% to the effective tax rate totaled $28 million for 2001. These items primarily related to state income taxes and goodwill amortization. Our reconciling items from the federal statutory rate of 35% to the effective tax rate totaled $26 million for 2002. See discussion above for 2002 reconciling items. See note 13 to our consolidated financial statements.

EBIT by Business Segment

The following tables present operating income (loss) and EBIT for each of our business segments for 2001, 2002 and 2003. The primary performance measure used by management to evaluate segment performance is EBIT from continuing operations, which at the segment level represents all profits or losses from continuing operations (both operating and non-operating) before deducting interest and taxes. Management believes EBIT is a good indicator of each segment's operating performance as it represents the results of operations without regard to financing methods or capital structure. In addition, we believe EBIT from continuing operations is used by our investors as a supplemental financial measure in the evaluation of our consolidated results of operations. Items excluded from EBIT are significant components in understanding and assessing our financial performance. Additionally, our computation of EBIT may not be comparable to other similarly titled measures computed by other companies, because all companies do not calculate it in the same fashion. For a reconciliation of our operating income (loss) to EBIT and EBIT to net income (loss), see below.

The following tables set forth our operating income (loss) and EBIT by segment for 2001, 2002 and 2003 reconciled to our consolidated net income (loss):

	Year Ended December 31, 2001				
	Retail Energy	Wholesale Energy	Other Operations	Eliminations	Consolidated
	(In millions)				
Total revenues	$188	$5,678	$ 11	$—	$5,877
Total operating expenses	(201)	(4,774)	(201)	—	(5,176)
Operating (loss) income	(13)	904	(190)	—	701
Gains from investments	—	—	23	—	23
Income of equity investments	—	7	—	—	7
Other, net	—	2	—	—	2
(Loss) earnings before interest and income taxes	(13)	913	(167)	—	733
Interest income, net					18
Income tax expense					290
Income from continuing operations					461
Income from discontinued operations, net of tax					99
Income before cumulative effect of accounting change					560
Cumulative effect of accounting change, net of tax					3
Net income					$ 563

	Year Ended December 31, 2002				
	Retail Energy	Wholesale Energy	Other Operations	Eliminations	Consolidated
	(In millions)				
Total revenues	$4,354	$6,585	$ 3	$(66)	$10,876
Total operating expenses	(3,824)	(6,588)	(67)	66	(10,413)
Operating income (loss)	530	(3)	(64)	—	463
Losses from investments	—	—	(23)	—	(23)
Income of equity investments	—	18	—	—	18
Loss on sale of receivables	(10)	—	—	—	(10)
Other, net	—	15	—	—	15
Earnings (loss) before interest and income taxes	520	30	(87)	—	463
Interest expense, net					(234)
Income tax expense					106
Income from continuing operations					123
Loss from discontinued operations, net of tax					(449)
Loss before cumulative effect of accounting change					(326)
Cumulative effect of accounting change, net of tax					(234)
Net loss					$ (560)

	Year Ended December 31, 2003				
	Retail Energy	Wholesale Energy	Other Operations	Eliminations	Consolidated
			(In millions)		
Total revenues	$5,936	$5,297	$ 1	$(234)	$11,000
Total operating expenses	(5,278)	(6,238)	(31)	234	(11,313)
Operating income (loss)	658	(941)	(30)	—	(313)
Gains from investments	—	—	2	—	2
Loss of equity investments	—	(2)	—	—	(2)
Loss on sale of receivables	(37)	—	—	—	(37)
Other, net	—	9	—	—	9
Earnings (loss) before interest and income taxes	621	(934)	(28)	—	(341)
Interest expense, net					(481)
Income tax expense					80
Loss from continuing operations					(902)
Loss from discontinued operations, net of tax					(416)
Loss before cumulative effect of accounting changes					(1,318)
Cumulative effect of accounting changes, net of tax					(24)
Net loss					$(1,342)

Retail Energy

Our retail energy segment provides electricity products and services to customers, ranging from residential and small commercial customers to large commercial, industrial and institutional customers. For a description of our retail energy segment, see "Our Business — Retail Energy" in Item 1 of this report and note 21 to our consolidated financial statements.

In 2002 and 2003, our retail energy segment was the largest contributor of income and cash flow. We view the retail business as relatively stable in the current competitive environment. We expect, given current trends in the wholesale energy markets, that this segment will be the primary contributor to our consolidated operating results in 2004. As the competitive market place in Texas evolves, we expect to lose residential and small commercial market share in the Houston market. We expect, based on current trends, that these customer losses will be partially offset by gains in residential and small commercial market share in other areas. Our efforts to gain customers outside of the Houston area may require us to increase our spending for marketing and advertising. Although our retail energy segment has recently expanded operations to focus on gaining commercial, industrial and institutional customers in the PJM Market, its primary market continues to be Texas. We expect to continue to renew contracts with a significant portion of our large commercial, industrial and institutional customers in the Texas and PJM markets, and where possible, add new customer contracts. For information regarding Texas price-to-beat regulations and other factors that could have a material impact on the results of operations of our retail energy segment, see "Our Business — Retail Energy" and "— Risk Factors."

We estimate a portion of our retail electricity sales and services and our energy supply costs. See "Critical Accounting Estimates" within this section. During 2003, we revised our estimates and assumptions related to 2002 and accordingly, recognized $39 million of income in our results of operations in 2003 related to 2002. These amounts are based on the latest information we have to date and as additional information becomes available, we will continue to recognize income and/or losses in future periods related to our historical results of operations.

As a part of our February 2004 cost reduction plan, we expect to restructure certain aspects of this segment, which may result in charges to earnings reflecting severance and other restructuring costs.

The following table provides summary data, including EBIT, of our retail energy segment for 2001, 2002 and 2003:

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Retail electricity sales and services revenues	$114	$3,001	$4,952
Revenues from resales of purchased power and other hedging activities	—	1,201	984
Contracted commercial, industrial and institutional margins (trading margins)	74	152	—
Total revenues	188	4,354	5,936
Operating expenses:			
Purchased power and delivery fees	6	3,226	4,683
Gross margin	182	1,128	1,253
Other operating expenses:			
Accrual for payment to CenterPoint	—	128	47
Operation and maintenance	109	211	236
Selling, general and administrative	75	233	277
Depreciation and amortization	11	26	35
Operating (loss) income	(13)	530	658
Loss on sale of receivables	—	(10)	(37)
(Loss) earnings before interest and income taxes	$(13)	$ 520	$ 621
Operations Data:			
Electricity sales (GWh):			
Residential		21,034	22,937
Small commercial		12,774	12,021
Large commercial, industrial and institutional(1)		26,928	29,041
Total		60,736	63,999
Customers as of December 31, 2002 and 2003 (in thousands, metered locations):			
Residential		1,478	1,607
Small commercial		214	210
Large commercial, industrial and institutional(1)		24	38
Total		1,716	1,855

(1) Includes volumes/customers of the Government Land Office for whom we provide services.

As described in note 2(d) to our consolidated financial statements, effective January 1, 2003, we discontinued the use of mark-to-market accounting for electricity sales to large commercial, industrial and institutional customers under executed contracts (and the related energy supply contracts) for contracts executed prior to October 25, 2002. The discontinuation of mark-to-market accounting was a result of our adoption of EITF No. 02-03. In addition, beginning October 1, 2003, we adopted EITF No. 03-11, which requires us to report a significant amount of our non-trading commodity hedging activities on a net, as opposed to a gross, basis. Accordingly, our financial results are not comparable between 2002 and 2003.

We must contract with other generators/suppliers to supply the majority of our obligations. We purchase and sell electricity supply in the market as a means to manage our energy supply. For example, we may purchase power in one zone of Texas and subsequently resell that power and purchase power in another zone of Texas based on changing energy supply needs. Prior to October 1, 2003, these transactions are recorded as gross revenues and purchased power and are disclosed in "revenues from resales of purchased power and other hedging activities" and "purchased power and delivery fees," as applicable.

2003 Compared to 2002

EBIT. Our retail energy segment's EBIT was $621 million for 2003 compared to $520 million for 2002. The increase of $101 million is detailed as follows (in millions):

Gross margins	$125
Accrual for payment to CenterPoint	81
Operation and maintenance and selling, general and administrative	(69)
Loss on sale of receivables	(27)
Depreciation and amortization	(9)
Net increase in income	$101

Total Revenues. Total revenues increased $1.6 billion during 2003 compared to 2002. However, as discussed above, the results of operations are not comparable between 2002 and 2003. The following table reconciles reported revenues to revenues from end-use customers on a comparable basis for 2002 and 2003 considering the impacts of applying EITF No. 02-03 and EITF No. 03-11:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Total revenues	$4,354	$5,936
To reflect additional revenues recorded on a net basis	1,722	168
	6,076	6,104
Less: Portion of revenues recorded on a net basis related to resales of purchased power acquired for hedging activities	(865)	(168)
Less: Revenues from resales of purchased power and other hedging activities	(1,201)	(984)
Gross revenues from end-use retail customers	$4,010	$4,952

The following details our gross revenues from end-use retail customers by customer class:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Texas(1):		
Residential and small commercial	$2,832	$3,473
Large commercial, industrial and institutional	1,178	1,439
Outside of Texas:		
Commercial, industrial and institutional	—	40
Gross revenue from end-use retail customers	$4,010	$4,952

(1) With respect to our customers in Texas, we experience seasonal peak loads in the months of June, July and August due to the weather.

The $942 million increase in revenues from end-use retail customers is due to (a) increases in the price-to-beat for residential and small commercial customers in the Houston area, (b) an increase in large commercial, industrial and institutional customers' rates that are indexed to the price of natural gas and new fixed-price contracts that were executed at higher prices, (c) a 9% increase in residential customers and sales volumes and (d) an increase in sales volumes to large commercial, industrial and institutional customers. These increases were partially offset by a decrease in small commercial customers. Our revenues from resales of purchased power and other hedging activities decreased due to changes in our strategies for risk management and hedging our electric energy supply.

Purchased Power and Delivery Fees. Purchased power and delivery fees increased $1.5 billion during 2003 compared to 2002. However, as discussed above, the results of operations are not comparable between 2002 and 2003. The following table reconciles reported purchased power and delivery fees to purchased power and delivery fees attributable to end-use customers on a comparable basis for 2002 and 2003 considering the impacts of applying EITF No. 02-03 and EITF No. 03-11:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Total purchased power and delivery fees	$3,226	$4,683
To reflect additional purchased power and delivery fees recorded on a net basis	1,722	168
	4,948	4,851
Less: Costs of purchased power subsequently resold and other hedging activities	(2,066)	(1,152)
Gross purchased power and delivery fees attributable to end-use retail customers	$2,882	$3,699

The $817 million increase in purchased power and delivery fees attributable to end-use retail customers is detailed as follows (in millions):

Higher energy costs primarily due to higher natural gas prices (see above) and increased volumes	$778
Increase in rates for ERCOT ISO load related fees	39
Net increase in expense	$817

Our costs of purchased power subsequently resold and other hedging activities decreased due to changes in our strategies for risk management and hedging our electric energy supply.

Gross Margins. Our retail energy segment's gross margins increased $125 million in 2003 compared to 2002. The increase is detailed as follows (in millions):

Higher revenue rates and volumes partially offset by higher purchased power and delivery fees	$182[1]
Revised estimates for electric sales and supply costs related to prior periods	39
Change in accounting method (EITF No. 02-03)	(57)
Increase in rates for ERCOT ISO load related fees	(39)
Net increase in income	$125

(1) Increase due to timing of price-to-beat fuel factor rate increases compared to higher fuel costs from changes in natural gas prices. Increase also due to higher customer count for residential and large commercial, industrial and institutional customers, as well as increased volumes for residential customers, partially offset by the impact of sales volumes for large commercial, industrial and institutional customers.

Accrual for Payment to CenterPoint. We will be required to make a payment to CenterPoint estimated to be due in the fourth quarter of 2004 related to residential customers. As of December 31,

2003, we estimate the payment to be $175 million. We accrued $128 million during 2002 and $47 million during 2003, for a total accrual of $175 million. See note 14(d) to our consolidated financial statements.

Operation and Maintenance and Selling, General and Administrative. Operation and maintenance expenses and selling, general and administrative expenses increased $69 million in 2003 compared to 2002. The increase is detailed as follows (in millions):

Employee-related, customer-related and other administrative costs	$36[1]
Corporate overhead charges	26[2]
Marketing costs	14[3]
Bad debt expense	(7)[4]
Net increase in expense	$69

(1) Increase due to increasing costs during 2002 to reach the normal operational level to serve customers in the Texas retail market.

(2) Increase due to (a) compensation, severance and benefit costs, (b) higher insurance costs, including property insurance and directors' and officers' insurance and (c) expenses associated with our corporate office move and related costs. In addition, our retail energy segment's proportion of the corporate overhead charges increased due to the increased support for this segment, which had increased operations in 2003 compared to 2002.

(3) Increase due to costs of additional marketing and other costs associated with obtaining new customers in areas outside of the Houston market.

(4) Decrease due to changes in regulations in September 2002, which allowed us to disconnect customers for non-payment of their electric bills.

Depreciation and Amortization. Depreciation and amortization expense increased $9 million in 2003 compared to 2002. The increase is primarily due to depreciation related to the information systems developed and placed in service during the first quarter of 2002.

Loss on Sale of Receivables. Loss on sale of receivables increased $27 million in 2003 compared to 2002. The increase is due to additional sales of receivables and increase in the discount factor pursuant to our receivables factoring facility. For additional information on our receivables facility, see note 16 to our consolidated financial statements.

2002 Compared to 2001

EBIT. Our retail energy segment's EBIT was $520 million for 2002 compared to a $13 million loss for 2001. The $533 million increase in EBIT was primarily due to the commencement of full competition, which began January 1, 2002 and resulted in increased margins related to retail electric sales to residential, small commercial and large commercial, industrial and institutional customers. The increase in margins was partially offset by increased operating expenses as further discussed below.

Total Revenues. Total revenues increased $4.2 billion in 2002 compared to 2001. The increase is due to (a) retail electric sales in the Texas retail market to residential, small commercial and large commercial, industrial and institutional customers in the Houston area in connection with full competition, which began January 1, 2002 and (b) our revenues from resales of purchased power and other hedging activities.

In addition, $53 million of revenues for 2001 were recorded for billing, customer service, credit and collection and remittance services charged to CenterPoint. The associated costs are included in operation and maintenance expenses and selling, general and administrative expenses. Our retail energy segment charged for these services provided at cost. The service agreement governing these services terminated on December 31, 2001.

Purchased Power and Delivery Fees. Purchased power expense and delivery fees increased $3.2 billion in 2002 compared to 2001. The increase is due to costs associated with retail electric sales and costs of purchased power subsequently resold and other hedging activities.

Gross Margins. Our retail energy segment's gross margins increased $946 million in 2002 compared to 2001. The increase is primarily due to the opening of the Texas market to full competition in January 2002. During 2002, the retail energy segment recognized $152 million of margins related to commercial, industrial and institutional electricity contracts (including $6 million of unrealized losses) compared to $74 million (including $73 million of unrealized gains) in 2001. For information regarding the accounting for electricity sales to large commercial, industrial and institutional customers, see note 2(d) to our consolidated financial statements.

Operation and Maintenance and Selling, General and Administrative. Operation and maintenance expenses and selling, general and administrative expenses increased $260 million in 2002 compared to 2001. The increase is detailed as follows (in millions):

Employee-related, customer-related and other administrative costs	$111 (1)
Bad debt expense	69 (2)
Gross receipt taxes	59 (3)
Corporate overhead charges	44 (4)
Marketing costs, primarily in Texas	23 (1)
General and administrative costs charged to CenterPoint in 2001	(53) (5)
Other, net	7
Net increase in expense	$260

(1) Increase primarily due to the Texas retail market opening to full competition in January 2002.

(2) Increase associated with the start-up of the retail electric market and regulations which, until September 2002, did not allow us to disconnect customers for non-payment of their electric bills.

(3) Increase relates to increased retail electric sales.

(4) Increase due to higher information technology costs, advisory fees, legal costs and insurance to support this segment.

(5) See discussion above.

Depreciation and Amortization. Depreciation and amortization expense increased $15 million in 2002 compared to 2001. The increase is detailed as follows (in millions):

Information systems	$17
Goodwill amortization in 2001	(2) (1)
Net increase in expense	$15

(1) See note 6 to our consolidated financial statements.

Loss of Sale of Receivables. Loss on sale of receivables increased $10 million in 2002 compared to 2001 reflecting the establishment of our receivables facility in 2002. See note 16 to our consolidated financial statements.

Wholesale Energy

As of December 31, 2003, our wholesale energy segment owned or leased electric power generation facilities with an aggregate net operating generating capacity of 19,442 MW (exclusive of units retired or mothballed). For a description of the wholesale energy segment, see "Our Business — Wholesale Energy" in Item 1 of this report and note 21 to our consolidated financial statements.

The EBIT of our wholesale energy segment has declined significantly since 2001 primarily as a function of depressed market conditions. In 2003, the EBIT of this segment was also negatively affected by an $80 million trading loss in the first quarter of that year. In March 2003, we discontinued our proprietary trading business.

In 2003, we (a) recognized an impairment of $985 million of goodwill in this segment, (b) retired 489 MW of plant assets and mothballed 824 MW of plant assets and (c) sold our 588 MW Desert Basin plant (see notes 6 and 23 to our consolidated financial statements). In February 2004, we announced our plans to mothball and/or retire an additional 727 MW from certain peaking plants and units that serve the PJM Market subject to a review of certain reliability issues with regulators.

Based on current trends, we do not anticipate that conditions in the wholesale energy markets are likely to improve significantly in 2004. However, we believe that the wholesale energy market is cyclical and that conditions will ultimately improve. For information regarding factors that could have a material impact on the results of operations of our wholesale energy segment, see "— Risk Factors."

As part of our February 2004 cost reduction plan, we expect to restructure certain aspects of this segment, which may result in charges to earnings reflecting severance and other restructuring costs.

The following table provides summary data, including EBIT, of our wholesale energy segment for 2001, 2002 and 2003:

	Year Ended December 31,		
	2001	2002(1)	2003(1)
		(In millions)	
Revenues	$ 5,374	$ 6,449	$ 5,346
Trading margins	304	136	(49)
Total revenues(2)	5,678	6,585	5,297
Operating expenses:			
Fuel and cost of gas sold(2)	1,576	1,082	1,414
Purchased power(2)	2,492	4,261	2,582
Gross margin(3)	1,610	1,242	1,301
Other operating expenses:			
Operation and maintenance	331	571	628
General, administrative and development	258	347	276
Wholesale energy goodwill impairment	—	—	985
Depreciation and amortization	117	327	353
Operating income (loss)	904	(3)	(941)
Other income (expense):			
Income (loss) of equity investments	7	18	(2)
Other, net	2	15	9
Earnings (loss) before interest and income taxes	$ 913	$ 30	$ (934)
Margins:			
Power generation(3)	$ 1,306	$ 1,106	$ 1,350
Trading	304	136	(49)
Total	$ 1,610	$ 1,242	$ 1,301
Power Generation Data(4):			
Wholesale power sales volumes (GWh)(5)	63,298	130,172	116,223
Wholesale power purchase volumes (GWh)(5)	37,490	86,741	70,701
Wholesale net power generation volumes (GWh)	25,808	43,431	45,522

(1) The results of operations and volumes for 2002 include the results of Orion Power from the date of acquisition (February 19, 2002), while the results for 2003 include a full year of Orion Power.

(2) In July 2003, the EITF issued EITF No. 03-11, which became effective October 1, 2003. At that time, we began reporting prospectively the settlement of sales and purchases of fuel and purchased power related to our non-trading commodity derivative activities that were not physically delivered on a net basis in our results of operations based on the item hedged pursuant to EITF No. 03-11. This resulted in decreased revenues and decreased fuel and cost of gas sold and purchased power of $666 million for the fourth quarter of 2003. We believe the application of EITF No. 03-11 will continue to result in a significant amount of our non-trading commodity derivative activities being reported on a net basis prospectively that were previously reported on a gross basis. We did not reclassify amounts for periods prior to October 1, 2003. See note 2(d) to our consolidated financial statements.

(3) Total revenues less fuel and cost of gas sold and purchased power.

(4) These amounts exclude volumes associated with our Desert Basin plant operations, which are classified as discontinued operations.

(5) Includes physically delivered volumes, physical transactions that are settled prior to delivery and hedge activity related to our power generation portfolio.

2003 Compared to 2002

EBIT. Our wholesale energy segment's EBIT was a loss of $934 million for 2003 compared to earnings of $30 million for 2002. The decrease of $964 million is detailed as follows (in millions):

Goodwill impairment	$(985)[1]
Trading margins	(185)
Operation and maintenance expense	(57)
Depreciation and amortization	(26)
Income/loss of equity investments	(20)
Power generation margins	244
General, administrative and development expense	71
Other, net	(6)
Net decrease in income	$(964)

(1) See note 6 to our consolidated financial statements.

Revenues. Our wholesale energy segment's revenues, excluding trading margins, decreased $1.1 billion in 2003 compared to 2002. The decrease is primarily due to (a) the application of EITF No. 03-11, which reduced 2003 revenues by $666 million (see note 2(d) to our consolidated financial statements) and (b) a 14% decrease in power sales volumes. The decrease is partially offset by (a) a 4% increase in prices for power sales partially due to increased gas costs, (b) $209 million of changes in our refund obligation and credit reserves for energy sales in California (see note 15(b) to our consolidated financial statements) and (c) $184 million due to the inclusion of a full year's results of Orion Power's operations in 2003 as the acquisition occurred in February 2002. Our revenues from power sales and other hedging activities decreased due to changes in our strategies and our liquidity constraints for risk management, hedging and optimizing of our generation portfolio.

Fuel and Cost of Gas Sold and Purchased Power. Our wholesale energy segment's fuel and cost of gas sold and purchased power decreased $1.3 billion in 2003 compared to 2002. The decrease is primarily due to (a) the application of EITF No. 03-11, which reduced 2003 fuel and cost of gas sold and purchased power by $666 million (see note 2(d) to our consolidated financial statements) and (b) decreased purchased power volumes and a decrease in prices of purchased power as a result of our hedging activities (see above).

Trading Margins. Trading margins decreased $185 million in 2003 compared to 2002. The decrease is primarily due to the discontinuance of proprietary trading in March 2003 and a pre-tax loss of approximately $80 million in connection with a financial gas spread position during the month of February 2003. In addition, the reduced market liquidity driven by the industry's restructuring contributed to the decrease. The decrease was partially offset by the impact of positive reserve and valuation adjustments

totaling $11 million recorded during 2003. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this report.

Power Generation Margins. Our wholesale energy segment's power generation margins increased $244 million in 2003 compared to 2002. The increase is detailed as follows (in millions):

California energy sales refund provision charges in 2002	$176[1]
California energy sales refund provision reversals in 2003	110[1]
Mid-Continent and New York regions — full year for Orion Power	70[2]
Mid-Atlantic region, excluding expiration of capacity contract	64[3]
ERCOT Region	29[4]
Margins associated with CenterPoint	18[5]
FERC settlement recorded in 2002	14[6]
Margins resulting from a terminated counterparty	12
Mid-Atlantic region — expiration of capacity contract	(66)
California energy sales credit provision reversals in 2002	(62)[1]
West region	(56)[7]
FERC settlement in October 2003	(37)[6]
New York region	(22)[8]
California energy sales credit provisions in 2003	(15)[1]
Other, net	9
Net increase in income	$244

(1) See note 15(b) to our consolidated financial statements.

(2) Increase due to the inclusion of a full year's results of Orion Power's operations in 2003, as the acquisition occurred in February 2002.

(3) Increase primarily due to increased margins from our coal plants due to higher power prices driven by increased natural gas prices.

(4) Increase primarily due to increased steam sales at the Channelview facility.

(5) Increase associated with billings to CenterPoint for engineering, technical and other support services provided to Texas Genco's facilities under a support agreement entered into in September 2002 (see note 3 to our consolidated financial statements).

(6) See note 15(a) to our consolidated financial statements.

(7) Decrease due to (a) lower spark spreads during 2003, (b) settlement of 2002 electric energy hedges entered into at higher prices and (c) an increase in losses due to hedge ineffectiveness.

(8) Decrease as a result of increased fuel costs due to unhedged fuel positions and forward power sales.

Operation and Maintenance. Operation and maintenance expenses for our wholesale energy segment increased $57 million in 2003 compared to 2002. The increase is detailed as follows (in millions):

Full year for Orion Power	$37
Facilities reaching commercial operation in 2002 and 2003	16[1]
Other, net	4
Net increase in expense	$57

(1) Increase due to the Hunterstown and Choctaw facilities reaching commercial operation in 2003 and the Channelview and Liberty facilities reaching commercial operation in 2002.

General, Administrative and Development. General, administrative and development expenses decreased $71 million in 2003 compared to 2002. The decrease is detailed as follows (in millions):

Development costs	$(41)[1]
Consulting fees and legal costs	(27)
Severance expense related to restructuring in 2002	(20)
Other salary and incentive costs	(14)
Provision for doubtful accounts	(12)
CFTC settlement in November 2003	18[2]
Corporate overhead allocations	18[3]
Other, net	7
Net decrease in expense	$(71)

(1) Decrease due to direct write-offs of development costs due to the cancellation of power generation projects in 2002 and less development activity in 2003.

(2) See note 15(a) to our consolidated financial statements.

(3) Increase due to (a) compensation, severance and benefit costs, (b) higher insurance costs, including property insurance and directors' and officers' insurance and (c) expenses associated with our corporate office move and related costs. This increase was partially offset for our wholesale energy segment as a higher proportion of the corporate overhead charges were allocated to our retail energy segment, which had increased operations in 2003 compared to 2002.

Depreciation and Amortization. Depreciation and amortization expense increased $26 million in 2003 compared to 2002. The increase is detailed as follows (in millions):

Full year for Orion Power	$ 21
Amortization of emission allowances due to higher average prices of allowances used	14
Early retirement of certain units at Sayreville and Etiwanda facilities in 2003	14
Two power generation facilities reaching commercial operation in 2003	14
Write-down of office building to fair value less costs to sell in 2003	7
Impairment charges related to turbines and generators in 2002	(37)[1]
Early retirement of certain units at the Warren facility in 2002	(15)
Other, net	8
Net increase in expense	$ 26

(1) See note 14(c) to our consolidated financial statements.

Income (Loss) of Equity Investments. The equity income/loss in both years primarily resulted from an investment in an electric generation plant in Boulder City, Nevada. The equity income related to our investment in the plant decreased $21 million in 2003 compared to 2002, primarily due to receipts of $22 million of business interruption and property/casualty insurance settlements during 2002.

2002 Compared to 2001

EBIT. Our wholesale energy segment's EBIT was $30 million for 2002 compared to $913 million for 2001. The decrease of $883 million is detailed as follows (in millions):

Power generation margins	$(807)[1]
Trading margins	(172)[1]
General, administrative and development expense	(89)[1]
Depreciation and amortization	(73)[1]
Orion Power acquisition in 2002	224
Operation and maintenance expense	13[1]
Other, net	21[1]
Net decrease in income	$(883)

(1) Excludes effects of the Orion Power acquisition, which occurred in February 2002. See note 5 to our consolidated financial statements.

Revenues. Our wholesale energy segment's revenues, excluding trading margins, increased $1.1 billion in 2002 compared to 2001. The increase is primarily due to (a) $2.2 billion in the Mid-Atlantic region as a result of hedging activities and (b) $1.1 billion related to the Orion Power acquisition in February 2002. The increase was partially offset by a $2.4 billion decrease in the West region as a result of reduced generation, reduced hedging activities and lower prices for power sales.

Fuel and Cost of Gas Sold and Purchased Power. Our wholesale energy segment's fuel and cost of gas sold and purchased power increased $1.3 billion in 2002 compared to 2001. The increase is primarily due to (a) $2.3 billion in the Mid-Atlantic region as a result of hedging activities and (b) $444 million due to the Orion Power acquisition. The increase was partially offset by a $1.7 billion reduction of generation volumes, reduced hedging activities and lower prices for fuel in the West region.

Trading Margins. Trading margins decreased $168 million in 2002 compared to 2001. The decrease is primarily due to lower commodity volatility in the power markets, reduced market liquidity driven by the industry's restructuring and the reduction of our trading activities as a result of our restructuring in 2002.

Power Generation Margins. Our wholesale energy segment's power generation margins decreased $200 million in 2002 compared to 2001. The decrease is detailed as follows (in millions):

West region	$(641)[1]
California energy sales refund provision charges in 2002	(176)[2]
Mid-Atlantic region	(68)[3][4]
Other regions	(54)[4][5]
Ineffectiveness of cash flow hedges	(28)[4][6]
Orion Power acquisition in 2002	608
Provision for Enron receivables and derivative assets	63[7]
California energy sales credit provision reversals in 2002	62[2]
ERCOT Region	29[8]
Other, net	5[4]
Net decrease in income	$(200)

(1) Decrease due to (a) the loosening of tight supply and demand conditions that existed in the first half of 2001, (b) a full year of energy price caps which were initially implemented in June 2001 and (c) other regulatory provisions that suppressed ancillary services revenues.

(2) See note 15(b) to our consolidated financial statements.

(3) Decrease due to a decline in power prices and reduced capacity revenues as a result of the expiration of a large capacity contract and lower capacity market conditions, which were primarily a result of increased generation supply in the region as well as regulatory intervention.

(4) Excludes effects of the Orion Power acquisition, which occurred in February 2002. See note 5 to our consolidated financial statements.

(5) Decrease primarily due to decreases in power prices, losses on our tolling contracts and increased gas transportation costs in 2002.

(6) Decrease due to $27 million gain in 2001 primarily related to the California market compared to $1 million loss in 2002. See note 7(a) to our consolidated financial statements.

(7) See note 15(a) to our consolidated financial statements.

(8) These assets began commercial operation in the last half of 2001 and in June 2002.

Operation and Maintenance. Operation and maintenance expenses for our wholesale energy segment increased $240 million in 2002 compared to 2001. The increase is detailed as follows (in millions):

Orion Power acquisition in 2002	$254
Lower maintenance and outage costs	(27)[1]
Other, net	13[1]
Net increase in expense	$240

(1) Excludes effects of the Orion Power acquisition, which occurred in February 2002. See note 5 to our consolidated financial statements.

General, Administrative and Development. General, administrative and development expenses increased $89 million in 2002 compared to 2001. The increase is detailed as follows (in millions):

Development write-offs in 2002	$27
Corporate overhead allocations	26[1]
Severance expense related to restructuring in 2002	20
Consulting costs related to restructuring in 2002	11
Bad debt expense	9
Development cost write-offs in 2001	(9)
Other, net	5
Net increase in expense	$89

(1) Increase due to higher information technology costs, advisory fees, legal costs and insurance.

Depreciation and Amortization. Depreciation and amortization expense increased $210 million in 2002 compared to 2001. The increase is detailed as follows (in millions):

Orion Power acquisition in 2002	$137
Impairment charges related to turbines and generators in 2002	37
Information technology systems placed in service in the third quarter of 2002	16
Early retirement of certain units at the Warren facility in 2002	15
Generating plants placed in service during second half of 2001 and in June 2002	14
Emissions credit amortization	(15)[1][2]
Goodwill amortization in 2001	(4)[3]
Other, net	10[2]
Net increase in expense	$210

(1) Decrease primarily due to higher amortization in the West region in 2001 due to increased power generation levels and higher prices for emission credits.

(2) Excludes effects of the Orion Power acquisition, which occurred in February 2002. See note 5 to our consolidated financial statements.

(3) See note 6 to our consolidated financial statements.

Income of Equity Investments. Our wholesale energy segment's income of equity investments increased $11 million in 2002 compared to 2001. The equity income in both years primarily resulted from an investment in an electric generation plant in Boulder City, Nevada. The increase is detailed as follows (in millions):

Business interruption and property/casualty insurance settlements receipts in 2002	$22
Decreases in margins due to lower prices realized in 2002	(5)
Other, net	(6)
Net increase in income	$11

Other Income, net. Other income, net increased $13 million in 2002 compared to 2001. The increase is primarily due to billings for software services to support the operations of generating facilities of Texas Genco.

Other Operations

Our other operations segment includes the operations of our venture capital business and unallocated corporate costs.

The following table provides summary data, including EBIT, of our other operations segment for 2001, 2002 and 2003:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Total revenues	$ 11	$ 3	$ 1
Operating expenses:			
Operation and maintenance	21	3	1
General and administrative	138	49	(1)
Depreciation and amortization	42	15	31
Total operating expenses	201	67	31
Operating loss	(190)	(64)	(30)
Other income (expense):			
Gain (loss) from investments	23	(23)	2
Loss before interest and income taxes	$(167)	$(87)	$(28)

2003 Compared to 2002

Other operation's loss before interest and income taxes was $28 million for 2003 compared to $87 million for 2002. The decrease of $59 million is detailed as follows (in millions):

Pre-tax, non-cash accounting settlement charge in 2002 for certain benefit obligations associated with our separation from CenterPoint	$(47)[1]
Impairment of certain venture capital investments in 2002	(32)[2]
Texas franchise taxes	8
Unallocated corporate costs associated with our discontinued European energy operations	7
Change in gains/losses from investments	8
Other, net	(3)
Net decrease in loss	$(59)

(1) See note 12 to our consolidated financial statements.

(2) See note 2(o) to our consolidated financial statements.

2002 Compared to 2001

Other operation's loss before interest and income taxes was $87 million for 2002 compared to $167 million for 2001. The decrease of $80 million is detailed as follows (in millions):

Pre-tax, non-cash charge recorded in 2001 relating to the redesign of some of CenterPoint's benefit plans in anticipation of our separation from CenterPoint	$(100)[1]
Restructuring charges in connection with exiting our communications business in 2001	(35)[2]
Goodwill impairment related to the exiting of our communications business in 2001	(19)[2]
Operating loss for our communications business in 2001	(18)
Pre-tax, non-cash accounting settlement charge in 2002 for certain benefit obligations associated with our separation from CenterPoint	47[1]
Impairment of certain venture capital investments in 2002	32[3]
Other, net	13
Net decrease in loss	$ (80)

(1) See note 12 to our consolidated financial statements.

(2) See note 17 to our consolidated financial statements.

(3) See note 2(o) to our consolidated financial statements.

Risk Factors

The following risk factors should be considered carefully together with the risk factors and contingencies described in "Business" in Item 1 of this report, "— Liquidity and Capital Resources" below, and notes 14 and 15 to our consolidated financial statements. The risks described in this section are not the only ones we face. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial could also have a material impact on our business operations.

Risks Relating to Selling Electricity

The wholesale and retail electricity markets are highly competitive.

The market for wholesale and retail electricity customers is very competitive. In certain markets, our principal competitors include the local regulated electric utility or its non-regulated affiliate. In other markets, we face competition from independent electric providers, independent power producers and

wholesale power providers. In many cases, our competitors have the advantage of long-standing relationships with customers, longer operating histories and/or larger and better capital resources.

In general, we compete on the basis of price, our commercial and marketing skills relative to other market participants, service and our financial position. Other factors affecting our competitive position include our ability to obtain at competitive prices fuel supplies to operate our generation plants, electricity for resale and related transportation/transmission services. Since many of our energy customers, suppliers and transporters require financial guarantees and other assurances regarding contract performance, our access to credit support is another factor affecting our ability to compete in the market.

Our largest market for residential electricity customers is the Houston market. As a former affiliate of CenterPoint, we are required by the PUCT to sell electricity to residential customers at a specified price, or "price-to-beat." If competing electric suppliers are able to sell electricity at prices below the price-to-beat, we risk losing a significant number of our residential customers to other providers. See "— Special Risks Relating to the Texas Market" below and "Our Business — Retail Energy — Regulation" in Item 1 of this report.

Our business is subject to market risks, the impact of which we cannot fully mitigate.

Unlike a traditional regulated electric utility, we are not guaranteed a rate of return on our capital investments. We sell electric energy, capacity and ancillary services and purchase fuel under short and long-term contractual obligations and through various spot markets. Our results of operations, financial condition and cash flows depend, in large part, upon prevailing market prices for electricity and fuel in our markets. Market prices may fluctuate substantially over relatively short periods of time, potentially adversely affecting our results of operations, financial condition and cash flows. Changes in market prices for electricity and fuel may result from the following factors among others:

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

We operate a significant number of power generation plants. To operate these plants, we must enter into commitments with various terms for fuel and transmission capacity or services. Although we attempt to hedge these purchases against our commitments to sell in the future, it is not possible to hedge all of our generation plant output beyond certain defined periods and, thus, changes in commodity prices could negatively impact our results of operations, financial condition and cash flows.

In marketing our products, we rely on power transmission facilities that we do not own or control. If these facilities fail to provide us with adequate transmission capacity, we may not be able to deliver power to our customers.

We depend on power transmission and distribution facilities owned and operated by utilities and others to deliver energy products to our customers. If transmission or transportation is inadequate or disrupted, our ability to sell and deliver our products may be hindered. Any infrastructure failure that interrupts or impairs delivery of electricity or natural gas could have a material adverse effect on our business.

We are dependent on metering systems that we do not own or control. Failure to receive accurate and timely information could have a material adverse impact on our business.

We are dependent on the transmission and distribution utilities for reading our customers' energy meters. We also rely on the local transmission and distribution utility or, in some cases, the independent system operator, to provide us with our customers' information regarding energy usage, and we may be limited in our ability to confirm the accuracy of the information. If we receive incorrect or untimely information from the transmission and distribution utilities, we will have difficulty properly billing our customers and collecting amounts owed to us. Failure to receive correct and timely information could have a material adverse effect on our results of operations, financial condition and cash flows. For information regarding data collection and other billing risks, see "— Special Risks Relating to the Texas Market" below and "Critical Accounting Estimates" below.

Risks Relating to Ownership of Generation Assets

Operation of power generation facilities involves significant risks that could negatively affect our results of operations, financial condition and cash flows.

As of December 31, 2003, we own an interest in, or lease, 124 operating electric generation facilities. Our operation of generation assets exposes us to risks relating to the breakdown of equipment, fuel supply interruptions, shortages of equipment, material and labor and other operational risks. In addition, significant portions 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 to or upgrade equipment to maintain efficiency, to comply with changing environmental requirements or to provide reliable operations. Such expenditures affect our operating costs. Any unexpected failure to produce power, including failure caused by breakdown or forced outage, could have a material adverse effect on our results of operations, financial condition and cash flows.

Our insurance coverage may not be sufficient and our insurance costs may increase.

We have insurance coverage, subject to various limits and deductibles, covering our generation facilities, including property damage insurance and general liability insurance in amounts that we consider appropriate.

However, we cannot assure you that insurance coverage will be available in the future on commercially reasonable terms or that the insurance proceeds received for any loss of or any damage to any of our generation facilities will be sufficient to restore the loss or damage without negative impact on our results of operations and financial condition. The costs of our insurance coverage have increased significantly during recent years and may continue to increase in the future.

Regulatory Risks

Our operations are subject to extensive regulation. Changes in these regulations could have a material adverse effect on our business, results of operations, financial condition and cash flows.

We operate in a regulatory environment that is undergoing significant changes as a result of varying restructuring initiatives at both the state and federal levels. We cannot predict the future direction of these

initiatives or the ultimate effect that this changing regulatory environment will have on our business. Moreover, existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to our facilities or our commercial activities. Such future changes in laws and regulations may have a detrimental effect on our business. For additional information, see "Our Business — Retail Energy — Regulation" and "Our Business — Wholesale Energy — Regulation" in Item 1 of this report and note 15 to our consolidated financial statements.

The FERC and independent system operators have imposed and may continue to impose price limitations, bidding rules and other mechanisms in an attempt to address some of the price volatility in these markets. Additionally, federal legislative initiatives have been introduced to address the problems being experienced in some power markets. We cannot predict whether such proposals will be adopted or their impact on industry restructuring. If the trend towards competitive restructuring of the wholesale power markets is reversed, discontinued or delayed, our business growth prospects and financial results could be adversely affected.

If we fail to obtain or maintain any necessary governmental permit or approval, we may not be able to operate our plants.

The 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. Most of our 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. Although the FERC has authorized us to sell electricity produced 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. Any reduction by the FERC of the rates we may receive for our generation activities may adversely affect our business, results of operations, financial condition and cash flows.

Our costs of compliance with environmental laws are significant and the cost of compliance with new environmental laws could adversely affect our results of operations and cash flows.

Our generation facilities, in particular our coal-fired plants, 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 costs to comply with these requirements. If we fail to comply with these requirements, we could be subject to civil or criminal penalties including fines. Existing environmental regulations can be revised, reinterpreted or become applicable to our facilities or new laws and regulations could be adopted. If any of these events occur, our business, results of operations, financial condition and cash flows could be materially adversely affected. For more information regarding compliance with environmental laws, see "Our Business — Environmental Matters" and note 15 to our consolidated financial statements.

Special Risks Relating to the Texas Market

Our results of operations could be materially affected by decisions of the PUCT regarding the "price-to-beat" and related regulatory matters.

The PUCT-approved price, or "price-to-beat," that we are required to charge for residential electricity sales and must make available to small commercial customers in the Houston area includes a component to reflect the market price of fuel and purchased power costs. This component, commonly known as the fuel factor, was originally established in 2001 and is fixed until such time as the PUCT grants an adjustment. Under current PUCT rules, we can apply for an adjustment not more than twice a year if we can demonstrate there have been significant changes in the market price of natural gas or purchased energy to serve retail customers. To the extent that there are significant changes in the market price of natural gas or purchased energy and we do not adjust the fuel factor or there is a significant delay in the

timing of these adjustments, our results of operations, financial condition and cash flows could be materially adversely affected.

The PUCT and the ERCOT ISO, which oversees the ERCOT Region, have and may continue to modify the market structure and other market mechanisms, seek to revise and/or modify or reinterpret existing regulations in ways that could have a material impact on our business in the Texas market. In addition, we may be subject to new state laws and regulations that are adopted or become applicable to our commercial activities in this region. Any of these actions could have a material adverse effect on our business.

We are dependent upon third party providers of capacity and energy to supply our retail customer obligations in Texas.

We do not own sufficient generating resources in Texas to supply all of the electricity requirements of our retail business in this market. Our inability to contract for our supply requirements, or the failure of our suppliers to perform their contractual obligations, could have a material adverse effect on our business. For additional information, see "Our Business — Retail Energy — Retail Energy Supply" and note 4 to our consolidated financial statements.

The ERCOT ISO has experienced a number of problems with its information systems since the advent of competition in the Texas market. Our operating results may be adversely affected if these problems are not alleviated.

The ERCOT ISO's responsibilities include ensuring that information relating to a customer's choice of retail electric provider, including data needed for ongoing servicing of customer accounts, is conveyed in a timely manner to the appropriate parties.

Problems in the flow of information between the ERCOT ISO, the transmission and distribution utilities and the retail electric providers have resulted in delays and other problems in enrolling and billing customers. When all involved parties do not successfully process customer enrollment transactions, ownership records in the various systems supporting the market are not synchronized properly and subsequent transactions for billing and settlement are adversely affected. The impact can include us not being the electric provider-of-record for intended or agreed upon time periods, delays in receiving customer consumption data that is necessary for billing, as well as the incorrect application of rates or prices and wholesale imbalances in our electricity supply and actual sales.

The ERCOT ISO is also responsible for handling scheduling and settlement for all electricity supply volumes in the ERCOT Region. 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. We and other retail electric providers schedule volumes based on forecasts, which are based, in part, on information supplied by the ERCOT ISO. To the extent that these amounts are not accurate or timely, we could have incorrectly estimated our scheduled volumes and supply costs.

See "Critical Accounting Estimates" in this section of the report for additional information.

Payment defaults by other retail electric providers to ERCOT could have a material adverse effect on our business.

In the event of a default by a retail electric provider of its payment obligations to ERCOT, the portion of the obligation that is unrecoverable by ERCOT is assumed by the remaining market participants in proportion to each participant's load ratio share. We would pay a portion of the amount owed to ERCOT should such a default occur if ERCOT is not successful in recovering such amounts. The default of a retail electric provider in its obligations to ERCOT could have a material adverse effect on our business.

Risks Related to Our Capital Structure

We have significant debt that could negatively impact our business.

As of December 31, 2003, we had total consolidated debt of $6.1 billion. Our high level of debt could:

- limit our ability to obtain additional financing to operate our business;
- limit our financial flexibility in planning for and reacting to business and industry changes;
- place us at a competitive disadvantage as compared to less leveraged companies;
- increase our vulnerability to general adverse economic and industry conditions, including changes in interest rates and volatility in commodity prices or a general decline in economic activity; and
- require us to dedicate a substantial portion of our cash flows to payments on our debt, thereby reducing the availability of our cash flow for other purposes including our operations, capital expenditures and future business opportunities.

Despite current indebtedness levels, we and our subsidiaries may still be able to incur substantially more debt.

As of December 31, 2003, our credit and other debt agreements permitted us to incur additional borrowings of up to $1.1 billion. If new debt is added to our current debt levels, the related risks that we now face could increase. See note 9 to our consolidated financial statements.

If we do not generate sufficient positive cash flows, we may be unable to service our debt.

Our ability, and the ability of our subsidiaries, to pay principal and interest on debt depends on our or our subsidiaries' future operating performance. If our or our subsidiaries' cash flows and capital resources are insufficient to allow us, or our subsidiaries, to make scheduled payments on the debt, we may have to reduce or delay capital expenditures, sell assets, seek additional capital, restructure or refinance the debt or sell equity. We cannot assure you that the terms of our debt will allow these alternative measures or that such measures would satisfy our scheduled debt service obligations.

If we default:

- our debt holders could declare all outstanding principal and interest to be due and payable;
- our secured debt lenders and bondholders could terminate their commitments and commence foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

We may not have adequate liquidity to post required amounts of additional collateral.

If commodity prices increase substantially in the near term, our liquidity could be severely strained by requirements under our commodity agreements to post additional collateral.

In certain cases, our counterparties have elected not to require us to post collateral to which they are otherwise entitled under certain agreements. However, these counterparties retain the right to request such collateral. Factors that could trigger increased demands for collateral include additional adverse changes in our industry, negative regulatory or litigation developments and/or changes in commodity prices. Based on current commodity prices, we estimate that as of February 20, 2004, we could be contractually required to post additional collateral of up to $243 million related to our operations.

The terms of our debt may severely limit our ability to respond to changes in our business.

Our credit facilities and other debt instruments restrict our ability to take specific actions in responding to changes in our business without the consent of our debt holders, even if such actions may be in our best interest.

Our credit facilities also require us to maintain specified financial ratios and meet specific financial tests.

In addition, our credit facilities and other debt instruments contain covenants that, among other things, restrict our ability to:

- pay dividends and other distributions;
- incur additional indebtedness and issue preferred stock;
- enter into asset sales;
- enter into transactions with affiliates;
- grant liens on assets to secure debt;
- engage in certain business activities; and
- engage in mergers or consolidations and transfers of assets.

Failure to comply with the covenants in our credit facilities and other debt instruments could have a material adverse effect on our results of operations and cash flows.

Our ability to comply with these covenants may be affected by many events beyond our control and our future operating results may make it impossible for us to comply with the covenants, or in the event of a default, to remedy that default. Our failure to comply with these financial covenants or with the other restrictions in our credit facilities and other debt instruments could result in a default, which could cause the applicable debt holders to declare that indebtedness to become immediately due and payable. If we are unable to repay those amounts, the holders of our debt could proceed against the collateral granted to them to secure the related indebtedness and take other legal action against us. If those lenders accelerate the payment of our debt, we cannot assure you that we could pay that indebtedness immediately and continue to operate our business.

An increase in our interest rates could adversely affect our cash flows.

As of December 31, 2003, we had $4.0 billion of outstanding floating rate debt. Any increase in short-term interest rates would result in higher interest costs and could adversely affect our results of operations, financial condition and cash flows. While we may seek to use interest rate swaps or other derivative instruments to hedge portions of our floating-rate exposure, we may not be successful in obtaining hedges on acceptable terms.

Our non-investment grade credit ratings and the perceived negative credit worthiness of merchant energy companies in the financial markets could adversely affect our ability to access capital on acceptable terms, commercialize our assets and engage in hedging activities.

Our credit ratings are below investment grade and are likely to remain below investment grade for the foreseeable future. Our non-investment grade credit ratings may continue to limit our ability to refinance our debt obligations and access the capital markets on terms that are favorable to us. In addition, to the extent that our credit ratings remain below investment grade, we are required under many commercial contracts to pledge cash collateral, post letters of credit or provide other similar credit support. These requirements constitute a significant constraint on our liquidity and cash resources, may negatively impact our ability to operate our business and could adversely affect our results of operations, financial condition and cash flows.

General Business Risks

Our strategic plans may not be successful.

Our future results of operations are dependent on the success of our strategic plans as discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview."

In restructuring our operations, we may encounter certain risks. For example, in exiting certain markets and business activities, we may forego opportunities to participate in potential business opportunities. In addition, as we review and make changes in our internal cost structure, we likely will incur increased short-term costs due to severance payments and restructuring processes. It is also possible that in restructuring and simplifying our operations we may increase the risk of an impairment of certain assets, such as information technology systems, to the extent that changes in our business eliminate the need for such assets.

As part of our cost-reduction efforts, we intend to consolidate a number of our internal risk controls and other support functions and make significant reductions in our corporate overhead. There is a potential that control systems designed for our previous operational structure may prove inadequate for our new operational structure and have to be redesigned. In addition, new risks may be encountered for which we have no existing control system. We believe that our internal controls will continue to be effective and adequate for our restructured operations, although there could be increased risks as a result of reduced personnel and changing processes, including information technology systems.

Although we believe that the wholesale energy market is cyclical, and that conditions will ultimately improve, there can be no assurance regarding the certainty, timing or magnitude of such improvement.

The ultimate outcome of lawsuits and regulatory proceedings to which we are a party could have a material adverse effect on our results of operations, financial condition and cash flows.

We are party to numerous lawsuits and regulatory proceedings relating to our historical trading and wholesale energy activities. In addition, various state and federal governmental agencies have commenced investigations relating to these activities, including the California Attorney General, the FERC, and criminal investigations by the United States Attorneys for the Northern District of California and the State of Texas. The ultimate disposition of some of these matters could have a material adverse effect on our results of operations, financial condition and cash flows. For additional information, see note 15 to our consolidated financial statements.

Our results of operations and our ability to access capital and insurance could be adversely affected by terrorist attacks or related acts of war.

The uncertainty associated with the military activity of the United States and other nations and the risk of future terrorist activity may affect 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 could be targets of terrorist activity. The risk of terrorist attacks or acts of war could also adversely affect the United States economy, create instability in the financial markets and, as a result, adversely affect our ability to access capital on terms and conditions acceptable to us.

Our business operations expose us to the risk of non-performance by counterparties.

Our operations are exposed to the risk that counterparties who owe us money or physical commodities and services, such as power, natural gas or coal, will not perform their obligations. Many of our counterparties in the energy markets have below-investment grade credit rankings. If these counterparties fail to perform, we might be forced to seek alternative hedging arrangements or replace the underlying commitment at then-current market prices. In this event, we might incur additional losses. See "Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks — Credit Risk" in Item 7A of this report.

Liquidity and Capital Resources

In this section, we discuss the principal sources of capital resources required for us to operate our business. We also identify known trends, demands, commitments, events or uncertainties that may affect our current and future liquidity or capital resources. In the last part of this section, we provide information regarding our historical cash flows.

Sources of Liquidity and Capital Resources

Our principal sources of liquidity and capital resources are cash flows from operations, borrowings under our various revolving credit facilities, proceeds from certain debt offerings and equity offerings and securitization of assets.

Cash Flows from Operations. All of our operations are conducted by our subsidiaries. As a result, Reliant Resources' cash flow is dependent upon the receipt from its subsidiaries of cash dividends, distributions or other transfers of cash generated by their operations. In 2002 and 2003, the primary source of cash flows from operations was from our retail energy segment. We expect that our retail operations will continue to be our primary source of operating cash flows through at least 2004. For a description of factors that could affect the cash flows from operations, see "— Risk Factors" above and notes 2(l) and 9 to our consolidated financial statements.

Credit Capacity, Cash and Cash Equivalents. The following table summarizes our credit capacity, cash and cash equivalents and current restricted cash at December 31, 2003:

	Total	Reliant Resources	Orion Power	Other
		(In millions)		
Total committed credit	$8,088[1]	$5,260	$2,007	$821
Outstanding borrowings	6,030[1]	3,343	1,880	807
Outstanding letters of credit	909	869	40	—
Unused borrowing capacity	1,149[2]	1,048	87[2]	14
Cash and cash equivalents	147	23	10	114
Current restricted cash(3)	251	7	212	32
Total	$1,547	$1,078	$ 309	$160

(1) As of December 31, 2003, we had consolidated current and long-term debt outstanding of $6.1 billion. As of December 31, 2003, $157 million of our committed credit facilities are to expire by December 31, 2004. For a discussion of our credit facilities, bonds, notes and other debt, see note 9(a) to our consolidated financial statements.

(2) As discussed in notes 9(a) and 15(c) to our consolidated financial statements, $5 million of the unused capacity relates to Liberty's working capital facility, which is currently not available to Liberty.

(3) Current restricted cash includes cash at certain subsidiaries, the transfer or distribution of which is effectively restricted by the terms of financing agreements but is otherwise available to the applicable subsidiary for use in satisfying certain of its obligations.

All of our major credit and other debt agreements contain restrictive covenants. Failure to comply with these covenants could have a number of effects, including limitations on our ability to make additional borrowings under our credit facilities, increases in borrowing costs and the acceleration of indebtedness. For additional information regarding these covenants, and the impact of a default under these covenants on our ability to borrow funds, see "— Risk Factors" and note 9 to our consolidated financial statements.

Shelf Registration. We currently have an effective shelf registration that allows us to issue up to an aggregate of $3.5 billion in securities. We have not yet issued any securities under this registration statement. However, we may, from time to time, sell any combination of debt securities, common stock, preferred stock and warrants in one or more offerings up to $3.5 billion.

Factors affecting Future Sources of Liquidity and Capital Resources. Although we are committed to identifying opportunities through restructuring our business operations and otherwise to reduce our liquidity needs, it is possible that we may need to incur additional debt or to issue equity or convertible instruments (subject to restrictions contained in our credit facilities and other debt agreements), to meet future obligations. Our ability to supplement our liquidity and capital resources could be affected by a number of factors, including those discussed under "— Risk Factors" above. In particular, the following factors could affect our ability to raise additional financings:

- general economic conditions, including economic conditions in the financial and capital markets and the availability of credit in such markets;
- the financial markets' expectations regarding:
  - the current and future performance and cash flows of our retail energy and wholesale energy operations;
  - the success of our efforts to reduce our cost structure and restructure our operations; and
  - our ability to successfully manage regulatory, litigation and other risks;
- the financial market's expectations regarding any plans we may have to issue additional equity or incur additional debt for purposes of acquiring individual ERCOT generating plants; and
- our credit ratings (as discussed in more detail below).

Although we have completed a number of financing transactions in 2003, we anticipate that continuing depressed conditions within the wholesale electric markets, our sub-investment grade credit ratings and other uncertainties will continue to have an impact on our ability to borrow funds on acceptable terms. If we require, but are unable to obtain, additional sources of financing to meet our future capital requirements, our financial condition and future results of operations could be materially adversely affected.

Our long-term credit ratings are, and are likely to remain for the next few years, below investment grade. Our long-term credit ratings are:

Date Assigned	Rating Agency	Rating(1)	Rating Description(2)	Rating
June 16, 2003	Moody's	B2	Stable Outlook	Unsecured
June 10, 2003	Standard & Poor's	B	Negative Outlook	Corporate
May 29, 2003	Fitch	B	Stable Outlook	Unsecured

(1) Each of the ratings assigned to us by Moody's, Standard & Poor's and Fitch are sub-investment grade.

(2) Moody's rating description represents its opinion regarding the likely direction of a rating over an approximately 18-month horizon. A stable outlook indicates that no change is expected. Standard & Poor's rating description accesses the potential direction of a credit rating over the intermediate to long term. A negative outlook means that a rating may be lowered. Fitch's rating description indicates the direction a rating is likely to move over a one to two-year period. A stable outlook indicates that no change is expected.

The ratings of our convertible senior subordinated notes and senior secured notes are:

Date Assigned	Rating Agency	Rating
$275 million 5.00% convertible senior subordinated notes due 2010:		
June 20, 2003	Moody's	B3
June 20, 2003	Standard & Poor's	CCC+
June 19, 2003	Fitch	B−

Date Assigned	Rating Agency	Rating
$550 million 9.25% senior secured notes due 2010:		
June 20, 2003	Moody's	B1
June 20, 2003	Standard & Poor's	B
June 27, 2003	Fitch	B+
$550 million 9.50% senior secured notes due 2013:		
June 20, 2003	Moody's	B1
July 23, 2003	Standard & Poor's	B
June 27, 2003	Fitch	B+

We cannot assure 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 agencies. Each rating should be evaluated independently of any other rating. For a discussion of the impact of previous downgrades in our credit ratings on our capital requirements, see "— Contractual Obligations and Contractual Commitments" below.

Liquidity and Capital Requirements

Our liquidity and capital requirements are primarily a function of our working capital needs, capital expenditures, debt service requirements and collateral requirements. Examples of working capital needs include purchases of fuel and electricity, plant maintenance costs (including required environmental expenditures) and corporate costs such as payroll.

In 2003, we began a review of our operating structure with the objective of reducing our costs. During 2003, we identified $140 million of annualized savings opportunities of which $25 million was realized in 2003 and $125 million is expected to be realized in 2004. Consistent with our business objectives and strategies described in "— Overview," in February 2004 we announced that we intend to reduce our net debt-to-adjusted EBITDA ratio significantly by the end of 2006. Consistent with this plan, we have targeted an additional $200 million in cost reductions. In addition, we have curtailed plans to construct any new generation plants (apart from the completion of projects that we are contractually committed to complete), retired or mothballed generation units that are no longer economic to operate and have sold non-core business operations and assets (e.g., our European energy operations). With the implementation of these strategies, we are seeking to restructure our operations and business with the objective of achieving by the end of 2006 credit metrics consistent with those that rating agencies currently ascribe to companies with investment grade status. Our ability to achieve this objective is subject to a number of assumptions, including our future economic performance. See "— Risk Factors."

In 2004, we intend to continue to identify and pursue opportunities to restructure our business operations in order to reduce our costs and our liquidity and capital requirements. However, our ability to reduce our cost structure, while maintaining prudent operating standards, is limited. In addition, we may incur short-term costs in the form of severance payments and other restructuring costs as part of our efforts to reduce our cost structure. Finally, there is a risk that, in restructuring our operations to focus on our core markets, we may be precluded from exploring business opportunities in other markets.

Capital Expenditures. The following table sets forth the capital expenditures we incurred in 2003 and the estimates of these expenditures for 2004 through 2006 (in millions):

	2003	2004	2005	2006
Maintenance capital expenditures:				
Retail energy	$ 23	$ 21	$ 20	$ 20
Wholesale energy	123	112	91	111
Other operations	43	17	16	16
	$189	$150	$127	$147
Construction of new generating facilities	398	125	—	—
Total capital expenditures	$587	$275	$127	$147

The future expenditures described in this table include the following expenditures:

- *Generating Projects.* As of December 31, 2003, we had two generating facilities under construction. We completed one in February 2004 and expect to complete the other in the third quarter of 2004. Total estimated cost of constructing these facilities is $1.2 billion. As of December 31, 2003, we had incurred $1.1 billion in construction costs, property, plant and equipment and spare parts inventory on these projects, which was funded from debt.
- *Environmental Expenditures.* We anticipate spending up to $122 million in capital expenditures from 2004 through 2006 for environmental compliance, totaling approximately $31 million, $22 million and $69 million for 2004, 2005 and 2006, respectively. In addition, we anticipate spending $40 million in capital expenditures for environmental compliance in 2007.

We have no further capital expenditure commitments in 2007 and 2008.

In addition, we expect to spend $16 million for 2004 through 2008 for pre-existing environmental conditions and remediations, all of which have been provided for in our consolidated balance sheet as of December 31, 2003 and are excluded from the table above.

Major Maintenance Expenses. The following table sets forth the major maintenance expenses we incurred in 2003 and the estimates of these expenses for 2004 through 2008 (in millions):

	2003	2004	2005	2006	2007	2008
Major maintenance cash expenses	$96	$113	$121	$97	$147	$119

Contractual Obligations and Contractual Commitments. In the following table, we provide disclosure concerning our obligations and commitments to make future payments under contracts, such as debt and lease agreements and purchase obligations, as of December 31, 2003 for 2004 through 2009 and thereafter:

Contractual Obligations	Total	2004	2005	2006	2007	2008	2009 and thereafter
			(In millions)				
Debt, including credit facilities(1)	$ 6,035	$ 161	$1,126[6]	$ 38	$1,994	$ 28	$2,688
REMA operating lease payments(2)	1,347	84	75	64	65	62	997
Other operating lease payments(2)	802	97	95	94	68	63	385
Trading and derivative liabilities(3)	573	357	99	60	24	13	20
Other commodity commitments(4)	4,018	1,529	763	321	151	106	1,148
Payment to CenterPoint(5)	175	175	—	—	—	—	—
Stadium naming rights(4)	266	10	10	10	10	10	216
Maintenance agreements obligations(4)	434	50	38	36	48	39	223
Other	13	3	5	5	—	—	—
Total contractual cash obligations	$13,663	$2,466	$2,211	$628	$2,360	$321	$5,677

(1) See note 9 to our consolidated financial statements.

(2) See note 14(a) to our consolidated financial statements.

(3) See note 7 to our consolidated financial statements.

(4) See note 14(f) to our consolidated financial statements.

(5) See note 14(d) to our consolidated financial statements.

(6) Included in this amount is $1.1 billion of Orion MidWest and Orion NY credit maturities (October 2005). Prior to their maturities, we believe that Orion MidWest's and Orion NY's future cash flows from operations will be sufficient to meet the scheduled principal payments and required prepayments. We anticipate refinancing any remaining outstanding borrowings prior to or upon maturity.

As a result of our March 2003 refinancing and our June and July 2003 capital markets debt issuances, our interest expense has increased substantially. For additional information, see note 9 to our consolidated financial statements.

In most cases involving our commercial contracts and/or guarantees, the impact of further rating downgrades is negligible. The following table details our cash collateral posted and letters of credit outstanding as of February 20, 2004:

	Total	Reliant Resources	Orion Power	Other
		(In millions)		
Cash collateral posted:				
For commercial operations	$ 120	$113	$ 7	$ —
In support of financings	42	—	—	42
	$ 162	$113	$ 7	$ 42
Letters of credit outstanding:				
For commercial operations	$ 618	$598	$20	$ —
In support of financings	440	—	17	423
	$1,058	$598	$37	$423

In certain cases, our counterparties have elected not to require us to post collateral to which they are otherwise entitled under certain agreements. However, these counterparties retain the right to request such collateral. Factors that could trigger increased demands for collateral include additional adverse changes in our industry, negative regulatory or litigation developments and/or changes in commodity prices. Based on current commodity prices, we estimate that as of February 20, 2004, we could be contractually required to post additional collateral of up to $243 million related to our operations. As of February 20, 2004, we had $31 million in unrestricted cash and cash equivalents and $959 million available under committed corporate facilities.

We are involved in a number of legal, environmental and other proceedings before courts and governmental agencies. We are also subject to ongoing investigations by various governmental agencies. Although we cannot predict the outcome of these proceedings, many of these matters involve substantial claim amounts which, in the event of an adverse judgment, could have a material adverse effect on our results of operations, financial condition and cash flows. For additional information, see note 15 to our consolidated financial statements.

Off-Balance Sheet Arrangements

In this section we discuss our off-balance sheet arrangements that have or are reasonably likely to have a current or future material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources. An off-balance sheet arrangement is any transaction, agreement or other contractual arrangement involving an unconsolidated entity under which a company has (a) made guarantees, (b) a retained or a contingent interest in

transferred assets, (c) an obligation under derivative instruments classified as equity or (d) any obligation arising out of a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the company, or that engages in leasing, hedging or research and development arrangements with the company.

In 2002, we formed a qualified special purpose entity as a bankruptcy remote subsidiary and entered into a receivables facility arrangement, which we amended in 2003. This arrangement with certain financial institutions allows them to purchase up to $350 million of undivided interests in our accounts receivable from certain retail customers (see notes 2(c) and 16 to our consolidated financial statements). We believe it improves cash flows while serving as a source of liquidity for our operations.

In 2000, we established three separate sale-leaseback transactions in connection with the acquisition of the REMA facilities. We used this off-balance sheet arrangement to finance, in part, the acquisition of these facilities (see notes 2(c) and 14(a) to our consolidated financial statements).

Certain off-balance sheet transactions that we do not expect to have a current or future material effect on our results of operations, financial condition or cash flows are disclosed in notes 8 and 14(e) to our consolidated financial statements. We also discuss certain arrangements to facilitate the development, construction, financing and leasing of three power generation projects, which we consolidated the subsidiaries effective January 1, 2003, in notes 2(c), 9 and 14(b) to our consolidated financial statements.

Historical Cash Flows

The following table provides an overview of cash flows relating to our operating, investing and financing activities in 2001, 2002 and 2003:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Cash (used in) provided by:			
Operating activities	$(152)	$ 519	$ 869
Investing activities	(838)	(3,486)	1,042
Financing activities	1,000	3,981	(2,888)

Cash Flows — Operating Activities

2003 Compared to 2002 and 2002 Compared to 2001. Net cash provided by operating activities increased $350 million in 2003 compared to 2002. Net cash provided by operating activities increased $671 million in 2002 compared to 2001. The increases are detailed as follows:

	Year Ended December 31,	
	2002 Compared to 2001	2003 Compared to 2002
	(In millions)	
Changes in working capital and other assets and liabilities	$322[1]	$313[3]
Changes in cash flows from operations, excluding working capital and other assets and liabilities	177[2]	(14)[4]
Changes in cash flows related to our discontinued operations	172	51
Net increase	$671	$350

(1) Decrease in net cash outflows from $568 million in 2001 to $246 million in 2002 due to decrease in cash used to meet working capital and other assets and liabilities requirements. See further analysis below.

(2) Increase in net cash inflows from $612 million in 2001 to $789 million in 2002 due primarily to cash flows provided by our retail energy segment for retail sales in 2002 due to the Texas retail market opening to full competition in January 2002, partially offset by a decline in cash flows of our wholesale energy segment due to a decline in operating results.

(3) Change in net cash outflows from $246 million in 2002 to net cash inflows of $67 million in 2003 due to decrease in cash used to meet working capital and other assets and liabilities requirements. See further analysis below.

(4) Decrease in net cash inflows from $789 million in 2002 to $775 million in 2003.

Year Ended December 31, 2003. Net cash provided by our operations in 2003 is detailed as follows (in millions):

Net cash flows from continuing operations, excluding changes in working capital and other assets and liabilities	$ 775[1]
Reduced cash requirements for margin deposits	221[2]
Decrease in accounts receivable	98[3]
Settlement of volumes delivered	66[4]
Changes in income tax receivables, net	56[5]
Net proceeds from receivables facility	23[6]
Decrease in accounts payable	(191)[7]
Net option premiums purchased	(101)[8]
Increase in restricted cash	(68)[9]
Net purchases of emissions credits	(65)
Purchase of interest rate caps	(29)[10]
Increase in lease payments related to REMA	(18)[11]
Discontinued operations	27
Other, net	75
Cash provided by operating activities	$ 869

(1) Due to both our retail energy segment's and wholesale energy segment's results of operations. See "— EBIT by Business Segment."

(2) Cash inflows related to our trading and hedging activities, as margin deposits were primarily replaced with letters of credit.

(3) Decrease primarily related to decrease in power sales volumes in our wholesale energy segment.

(4) Relates to volumes delivered under contracted electricity sales to large commercial, industrial and institutional customers and the related energy supply contracts, which were previously recognized as unrealized earnings in prior periods (see note 2(d) to our consolidated financial statements).

(5) Decrease primarily due to net tax refunds, primarily federal, of $75 million received in 2003.

(6) See note 16 to our consolidated financial statements.

(7) Decrease primarily associated with the decrease in purchased power and fuel purchases in our wholesale energy segment as a result of decreased hedging activities.

(8) Purchases relate to our retail energy segment's hedging activities.

(9) Increase primarily related to funds dedicated for the support of lease obligations of REMA and activities of Orion NY. See note 2(l) to our consolidated financial statements.

(10) See note 9(c) to our consolidated financial statements.

(11) See note 14(a) to our consolidated financial statements.

Year Ended December 31, 2002. Net cash provided by our operations in 2002 is detailed as follows (in millions):

Net cash flows from continuing operations, excluding changes in working capital and other assets and liabilities	$ 789[1]
Decrease in restricted cash	282[2]
Decrease in collateral deposits related to an operating lease	136[3]
Two structured transactions settled in 2002	121[4]
Net proceeds from receivables facility	95[5]
Decrease in accounts payable	(239)[6]
Increase in margin deposits paid	(193)[7]
Increase in accounts receivable	(136)[8]
Increase in lease payments related to REMA	(79)[9]
Increase in inventory	(74)[10]
Settlement of forward starting swaps	(55)[11]
Discontinued operations	(24)
Other, net	(104)
Cash provided by operating activities	$ 519

(1) Due to both our retail energy segment's and wholesale energy segment's result of operations. See "— EBIT by Business Segment."

(2) Decrease primarily attributable to REMA's funds becoming effectively unrestricted pursuant to REMA's lease obligations, partially offset by Orion Power's operations.

(3) See note 14(c) to our consolidated financial statements.

(4) See note 7(a) to our consolidated financial statements.

(5) See note 16 to our consolidated financial statements.

(6) Decrease primarily due to timing of cash payments of our wholesale energy segment.

(7) Cash outflows for margin deposits are related to our trading and hedging activities and increased partially due to downgrades in our credit ratings in 2002.

(8) Increase due to the start-up of our retail energy segment in 2002 as a result of the opening of the Texas retail market to full competition in January 2002.

(9) See note 14(a) to our consolidated financial statements.

(10) Increase due primarily to fuel inventory related to our wholesale energy segment.

(11) See note 9(c) to our consolidated financial statements.

Year Ended December 31, 2001. Net cash used in our operations in 2001 is detailed as follows (in millions):

Net cash outflows from continuing operations, excluding changes in working capital and other assets and liabilities	$ 612[1]
Decrease in accounts payable	(1,112)[2]
Increase in lease payments related to REMA	(181)[3]
Deposits in a collateral account related to an operating lease	(145)[4]
Increase in restricted cash primarily related to REMA	(117)[5]
Two structured transactions entered into in 2001	(117)[6]
Decrease in accounts receivable	809[7]
Decrease in margin deposits paid	167[8]
Change in intercompany balances with CenterPoint	94
Discontinued operations	(196)
Other, net	34
Cash used in operating activities	$ (152)

(1) Due primarily to our wholesale energy segment's results of operations. See "— EBIT by Business Segment."

(2) Decrease primarily due to decline in average price paid for gas purchases related to our wholesale energy segment.

(3) See note 14(a) to our consolidated financial statements.

(4) Net collateral deposits paid by us. See note 14(c) to our consolidated financial statements.

(5) See notes 2(l) and 9 to our consolidated financial statements.

(6) See note 7(a) to our consolidated financial statements.

(7) Decrease due to decline in revenues due to lower power prices coupled with timing of cash receipts related to our wholesale energy segment.

(8) Decrease related to reduced net margin deposits on energy trading and hedging activities as a result of reduced commodity volatility and relative price levels of natural gas and power.

Cash Flows — Investing Activities

2003 Compared to 2002. Net cash provided by/used in investing activities changed by $4.5 billion in 2003 compared to 2002, primarily due to the acquisition of Orion Power for $2.9 billion in 2002. In addition, cash flows provided by investing activities of our discontinued operations increased $1.5 billion in 2003 compared to 2002. See below.

2002 Compared to 2001. Net cash used in investing activities increased $2.6 billion in 2002 compared to 2001, primarily due to the acquisition of Orion Power for $2.9 billion in 2002. In addition, cash flows from investing activities of our discontinued operations changed by $231 million in 2002 compared to 2001.

Year Ended December 31, 2003. Net cash provided by investing activities during 2003 was $1.0 billion, primarily due to cash inflows of $1.6 billion from our discontinued operations primarily due to net proceeds from the sales of our Desert Basin plant operations ($285 million) and our European energy operations ($1.4 billion). See notes 22 and 23 to our consolidated financial statements. This was offset by cash outflows due to capital expenditures of $587 million primarily related to our power generation operations and development of power generation projects.

Year Ended December 31, 2002. Net cash used in investing activities during 2002 was $3.5 billion, primarily due to the acquisition of Orion Power for $2.9 billion in February 2002 and $640 million in capital expenditures primarily related to our power generation operations and development of power generation projects. This was offset by cash inflows of $119 million from our discontinued operations primarily due to a $137 million cash dividend from our discontinued European energy operation's equity investment in NEA.

Year Ended December 31, 2001. Net cash used in investing activities during 2001 was $838 million, primarily due to $728 million of capital expenditures primarily related to our power generation operations and to a lesser extent by cash outflows of $112 million from our discontinued operations.

Cash Flows — Financing Activities

2003 Compared to 2002. Net cash used in/provided by financing activities during 2003 changed by $6.9 billion compared to 2002. See below for discussion.

2002 Compared to 2001. Net cash provided by financing activities during 2002 increased by $3.0 billion compared to 2001. See below for discussion.

Year Ended December 31, 2003. Net cash used in financing activities in 2003 is detailed as follows (in millions):

Prepayments of senior secured term loans	$(2,048)[1]
Net payments of senior secured revolving credit facility	(1,108)[1]
Prepayment of senior revolving credit facility in conjunction with March 2003 refinancing	(350)[1]
Payments of financings costs	(184)[2]
Net payments on Orion MidWest and Orion NY term loans and revolving working capital facilities	(153)
Net proceeds from senior secured notes issued July 2003	1,056[1]
Net proceeds from convertible senior subordinated notes issued June and July 2003	266[1]
Net proceeds from additional PEDFA bond issuance for Seward generation plant	99[1]
Net borrowings under a financing commitment	95[3]
Draws under letters of credit to provide support for REMA's lease obligations	42[1]
Discontinued operations	(734)[4]
Other, net	131
Cash used in financing activities	$(2,888)

(1) See note 9 to our consolidated financial statements.

(2) See note 2(r) to our consolidated financial statements.

(3) Net borrowings due to construction agency financing commitment for the construction of three power generation facilities in the first quarter of 2003 prior to the March 2003 refinancings. See notes 9(a) and 14(b) to our consolidated financial statements.

(4) See note 22 to our consolidated financial statements.

Year Ended December 31, 2002. Net cash provided by financing activities during 2002 of $4.0 billion is primarily due to an increase in short-term borrowings used to fund the acquisition of Orion Power and an increase in working capital to meet future obligations and other working capital requirements. In addition, net cash provided by financing activities increased due to decreased investments of excess cash in an affiliate of CenterPoint. These cash inflows were partially offset by (a) the purchase of $200 million in principal amount of the Orion Power Holdings 4.5% convertible senior notes and (b) the payment of $145 million under our Orion MidWest and Orion NY credit agreements. See note 9(a) to our consolidated financial statements.

Year Ended December 31, 2001. Net cash provided by financing activities during 2001 of $1.0 billion is primarily due to net proceeds from the IPO of $1.7 billion, offset by $731 million of changes in notes with affiliated companies and a $189 million treasury stock purchase. Pursuant to the terms of the master separation agreement with CenterPoint, we used $147 million of the net IPO proceeds to repay certain indebtedness owed to CenterPoint. Proceeds not initially utilized from the IPO during 2001 were advanced on a short-term basis to CenterPoint, which provided a cash management function. As of December 31, 2001, we had $390 million of outstanding advances to CenterPoint. During 2001 and 2002, the IPO

proceeds were used for repayment of third party borrowings, repurchase of our common stock, capital expenditures and payment of taxes, interest and other payables. In May 2001, prior to the closing of the IPO, CenterPoint converted to equity or contributed to us an aggregate of $1.7 billion of indebtedness owed by us to CenterPoint of which $35 million was related accrued intercompany interest expense. Following the IPO, CenterPoint no longer provided financing or credit support for us, except for specified transactions or for a limited period of time.

New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates

New Accounting Pronouncements

For discussion regarding new accounting pronouncements that will impact us, see note 2(v) to our consolidated financial statements.

Significant Accounting Policies

For discussion regarding our significant accounting policies, see note 2 to our consolidated financial statements.

Critical Accounting Estimates

As required by GAAP, we make a number of estimates and judgments in preparing our consolidated financial statements. These estimates, to the extent they differ from actual results, can have a significant impact on our recorded assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. In this section, we discuss those estimates that we deem to be "critical accounting estimates." We consider an estimate to be a material "critical accounting estimate" due to either (a) the level of subjectivity or judgment necessary to account for highly uncertain matters or (b) the susceptibility of such matters to change, and that have a material impact on the presentation of our financial condition or results of operations. The audit committee of our board of directors reviews each critical accounting estimate with our senior management.

Goodwill.

As of November 1 of each year, we test goodwill for each of our segments. In addition, we test goodwill if an event occurs indicating that an asset carrying value may not be recoverable. The following table shows net goodwill by reportable segment for the indicated period:

	December 31,					
	2002			2003		
	Retail Energy	Wholesale Energy	Consolidated	Retail Energy	Wholesale Energy	Consolidated
	(In millions)					
Goodwill	$32	$1,509	$1,541	$53	$430	$483

In 2001, we determined goodwill associated with our communications business was impaired and recorded a goodwill impairment of $19 million that was reported in amortization expense. In 2002, we recognized impairment charges totaling $716 million related to our European energy segment goodwill ($234 million reported as a cumulative effect of a change in accounting principle and $482 million reported as a component of loss from discontinued operations). In 2003, we recognized impairment charges totaling $985 million related to our wholesale energy reporting unit. For information regarding impairment charges reflected in the reported periods in our consolidated financial statements, see note 6 to our consolidated financial statements.

We estimate the fair value of our wholesale energy segment based on a number of subjective factors, including: (a) appropriate weighting of valuation approaches (income approach, market approach and comparable public company approach), (b) projections about future power generation margins,

(c) estimates of our future cost structure, (d) discount rates for our estimated cash flows, (e) selection of peer group companies for the public company approach, (f) required level of working capital, (g) assumed terminal value and (h) time horizon of cash flow forecasts.

We consider the estimate of fair value to be a critical accounting estimate for our wholesale energy segment because (a) a potential goodwill impairment could have a material impact on our financial position and results of operations and (b) the estimate is based on a number of highly subjective judgments and assumptions. We do not consider the estimate of fair value and goodwill of our retail energy segment to be a critical accounting estimate as our prior estimates of fair value for that reporting unit significantly exceeded the carrying value.

In determining the fair value of our wholesale energy segment in 2003, we made the following key assumptions: (a) the markets in which we operate will continue to be deregulated; (b) demand for electricity will grow, which will result in lower reserve margins; (c) there will be a recovery in electricity margins over time to a level sufficient such that companies building new generation facilities can earn a reasonable rate of return on their investment and (d) the economics of future construction of new generation facilities will likely be driven by regulated utilities. As part of our process, we modeled all of our power generation facilities and those of others in the regions in which we operate. The following table summarizes certain of these significant assumptions:

	January 2002	November 2002	July 2003	November 2003
Number of years used in internal cash flow analysis(1)	5	15	15	15
EBITDA multiple for terminal values(2)	6.0	7.0 to 7.5	7.5	7.5
Risk-adjusted discount rate for our estimated cash flows	9.0%	9.0%	9.0%	9.0%
Average anticipated growth rate for demand in power(3)	2.0%	2.0%	2.0%	2.0%
After-tax return on investment for new investment(4)	9.0%	9.0%	7.5%	7.5%

(1) The numbers of years used in the internal cash flow analysis changed from 5 years in the January 2002 test to 15 years due to the fact that five years in the forecast did not capture the full impact of the cyclical nature of our wholesale energy operations. Additional periods were included in the forecasts to derive an appropriate forecast period, which was used to determine the estimated terminal value. As of January 2002, based on current market conditions in the wholesale energy industry, management did not believe additional periods beyond five years in the forecast were required.

(2) The EBITDA multiple for terminal values changed from 6.0 in the January 2002 test to 7.0 to 7.5 in the November 2002 test and from 7.0 to 7.5 in the November 2002 test to 7.5 in the 2003 tests due to the independent appraiser's updated analysis of the public guideline companies that indicated higher multiples were appropriate to calculate the terminal values at the applicable dates.

(3) Depending on the region, the specific rate is projected to be somewhat higher or lower.

(4) Based on our assumption in 2003 that regulated utilities will be the primary drivers underlying the construction of new generation facilities, we have assumed that the after-tax return on investment will yield a return representative of a regulated utility's cost of capital (7.5%) rather than that of an independent power producer (9.0%). Based on changes in assumed market conditions, including regulatory rules, we have changed the projected time horizon for substantially achieving the after-tax return on investment to 2008 — 2012 (depending on region). Formerly, we had assumed that the time horizon for substantially achieving this rate of return was 2006 — 2010.

Because we recognized a goodwill impairment in 2003, in the near future, if our wholesale energy market outlook changes negatively, we could have additional impairments of goodwill that would need to be recognized. In addition, our ongoing evaluation of our wholesale energy business could result in decisions to mothball, retire or dispose of additional generation assets, any of which could result in additional impairment charges related to goodwill, impact our fixed assets' depreciable lives or result in fixed asset impairment charges.

California Net Receivables.

As described in note 15(b) to our consolidated financial statements, we have recorded a $189 million net receivable, included in the $242 million below, as of December 31, 2003 for energy sales in California during the period from October 2, 2000 through June 20, 2001. The receivable is an estimate based on a

number of assumptions regarding (a) the outcome of a FERC refund proceeding and (b) the realizability of the receivables due to creditworthiness issues.

We consider this estimate, which affects only our wholesale energy segment, to be a critical accounting estimate because (a) changes in this estimate can have a material impact on our financial position and results of operations and (b) the estimate of the net receivable is based on a number of highly subjective judgments and assumptions. In estimating the net receivable, we have made a number of assumptions, as set forth in the following table, regarding (a) the estimated refund obligation, (b) the credit reserve and (c) the interest receivable:

	December 31,	
	2002	2003
	(In millions)	
Accounts receivable, excluding refund obligation	$306	$326
Refund obligation	(191)	(81)
Credit reserve	(6)	(21)
Interest receivable	5	18
Accounts receivable, net	$114	$242

For information regarding related changes in our estimates, see note 15(b) to our consolidated financial statements.

Property, Plant and Equipment.

We evaluate our property, plant and equipment for impairment if events indicate that the carrying value of these assets may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, we recognize an impairment by subtracting the fair value of the asset from its carrying value. We consider the fair value estimate to be a critical accounting estimate because (a) an impairment can have a material impact on our financial position and results of operations and (b) the highly subjective nature of the many judgments and assumptions used in the estimate. The estimate of carrying value primarily affects our wholesale energy segment, which holds approximately 97% of our total net property, plant and equipment.

In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to: (a) whether an indicator of impairment has occurred, (b) the grouping of assets, (c) the intention of "holding" versus "selling" an asset, (d) the forecast of undiscounted expected future cash flow over the asset's estimated useful life and (e) if an impairment exists, the fair value of the asset or asset group. If our wholesale energy market outlook changes negatively, we could have additional impairments of our property, plant and equipment in future periods. Additionally, future decisions to mothball, retire or dispose of assets could result in impairment charges. It is also possible that in restructuring and simplifying our operations in the future as discussed in "— Overview" of this section, we may increase the risk of an impairment of certain assets, such as information technology systems, to the extent that changes in our business eliminate the need for such assets.

During 2001, we decided to exit our communications business and recorded fixed asset impairments of $22 million, which is recorded in depreciation expense (see note 17 to our consolidated financial statements). During 2002, we recognized a $37 million impairment recorded in depreciation expense related to steam and combustion turbines and two heat recovery steam generators (see note 14(c) to our consolidated financial statements). During 2003, we recognized depreciation expense of $7 million related to the write-down of an office building to its fair value less cost to sell, which was determined with the assistance of an independent appraiser.

For information concerning the possible impairment of our Liberty plant, see note 15(c) to our consolidated financial statements.

Depreciation Expense.

As of December 31, 2003, approximately 73% of our total gross property, plant and equipment was comprised of electric generation facilities and equipment. We estimate depreciation expense using the straight-line method based on projected useful lives. We consider these estimates, which affect primarily our wholesale segment, to be critical accounting estimates because (a) they require subjective judgments regarding the estimated useful lives of property, plant and equipment and (b) changes in the estimates could affect future depreciation expense and hence our results of operations.

In 2002, we recognized $15 million in depreciation expense for the early retirement of power generation units at the Warren facility. During 2003, we recognized $14 million in depreciation expense for the early retirement of power generation units at two facilities. For additional information regarding depreciation expense, see note 2(f) to our consolidated financial statements.

For power generation facilities purchased in acquisitions, we estimate useful life based on: (a) the condition of the acquired facilities, (b) the fuel type of the generation facilities, (c) future environmental requirements, (d) projected maintenance and (e) projected future cash flows. For power generation facilities that we construct, we use the design life provided in the construction contract. In the absence of a specified design life, we estimate the weighted average life of the components of a power generation unit of a facility.

Significant portions of our facilities were constructed many years ago. Older generating equipment may require significant upgrades, which could affect judgments to their useful life. In addition, alternative technologies could reduce the useful lives of portions of these facilities.

If we had assumed that our gross property, plant and equipments' lives had decreased by 10% from the estimated lives used in our calculation of depreciation expense for 2003, our depreciation expense would have been approximately $399 million or 11% higher.

Trading and Derivative Activities.

Legacy Trading Positions. We report our legacy trading positions on our consolidated balance sheets at fair value. As discussed in Item 7A "Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks" of this report, we determine the fair value of our trading assets/liabilities based on (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

We consider the fair values of our trading assets/liabilities to be a critical accounting estimate because they are highly susceptible to change from period to period and are dependent on many subjective factors, including (a) estimated forward market price curves; (b) valuation adjustments relating to time value; (c) liquidity valuation adjustments, calculated by utilizing observed market price liquidity, which represent the estimated impact on fair values resulting from the widening of bid/ask spreads for transactions occurring further in the future; (d) costs of administering future obligations under existing contracts and (e) credit adjustments based on estimated defaults by counterparties that are calculated using historical default probabilities for corporate bonds for companies with similar credit ratings. These estimates affect our wholesale energy segment and, prior to 2003, our retail energy segment.

To determine the fair value for energy trading derivatives where there are no market quotes or external valuation services, we rely on modeling techniques. In certain circumstances, prices are modeled using a variety of techniques such as moving averages, calibration models and other time series techniques, market equilibrium analysis, extrapolation/interpolation, a range of contingent claims valuation methods and volumetric risk modeling. There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

Non-Trading Derivative Activities. We report our non-trading derivative assets/liabilities on our consolidated balance sheets at fair value. As discussed in Item 7A "Quantitative and Qualitative

Disclosures about Non-Trading and Trading Activities and Related Market Risks" of this report, we estimate the fair value of our non-trading derivative assets/liabilities based on (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods. The fair values and deferred gains and losses of our non-trading derivative instruments and contractual commitments qualifying and designated as hedges are based on the same valuation techniques described above for energy trading activities.

We consider the fair values of our non-trading derivative instruments to be a critical accounting estimate due to the same factors applicable to our legacy trading activities. We also believe estimates regarding the probability that hedged forecasted transactions will occur by the end of the time period specified in the original hedging documentation to be a critical accounting estimate. These estimates affect all of our reportable operating segments.

For additional information regarding our legacy trading positions and non-trading derivative activities, see notes 2(d), 7 and 9(c) to our consolidated financial statements and Item 7A "Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks." Item 7A includes value-at-risk information related to our legacy trading positions and an analysis of the impact a 10% hypothetical adverse change on the fair value of our non-trading derivatives at December 31, 2002 and 2003.

Retail Energy Segment Estimated Revenues and Energy Supply Costs.

Accrued Unbilled Revenues. In 2003, accrued unbilled revenues of $290 million represented approximately 3% of our consolidated revenues and 5% of our retail energy segment's revenues. In 2002, accrued unbilled revenues of $216 million represented approximately 2% of consolidated revenues and 5% of our retail energy segment's revenues.

Accrued unbilled revenues are based on our estimate of the amount of energy delivered to customers since the date of the last meter reading and on customer metering information (which we have limited ability to confirm) furnished to us by the ERCOT ISO. In estimating electricity usage volumes, we rely upon daily forecasted volumes, estimated customer usage by class and applicable customer rates based on analyses reflecting significant historical trends and experience. Volume estimates by customers are then multiplied by our estimated rate by customer class to calculate the unbilled revenues to be recorded. We record the unbilled revenues in the current reporting period and then reverse it in the subsequent reporting period when actual usage and rates are known and billed.

We consider our estimate of accrued unbilled revenue to be a critical accounting estimate because of (a) the uncertainty inherent in estimating customer volumes, (b) the problems or delays in the flow of information between the ERCOT ISO, the transmission and distribution utilities and us and other retail electric providers, (c) the potential negative impact on our business, results of operation and cash flows based on the receipt of inaccurate or delayed information from the transmission and distribution utilities or the ERCOT ISO and (d) the fact that as additional information becomes available, the impact of recognizing revised estimates in subsequent periods relating to a previous period can be material to our retail energy segment's and our consolidated results of operations. If our estimate of either electricity usage volumes or estimated rates were to increase or decrease by 3%, our accrued unbilled revenues at December 31, 2003 would have increased or decreased by approximately $9 million. A 3% increase or decrease in both our estimated electricity usage and estimated rates would have increased or decreased our accrued unbilled revenues at December 31, 2003 by approximately $17 million.

Estimated Energy Supply Costs. We record energy supply costs for electricity sales and services to retail customers based on estimated supply volumes and an estimated rate per MWh for the applicable reporting period. We consider this accounting estimate to be a critical accounting estimate because of (a) the uncertainty inherent in estimating both the supply volumes and the rate per MWh and (b) the uncertainty related to the ERCOT ISO settlement process (as discussed below) and (c) the fact that, as additional information becomes available, the impact of recognizing revised estimates in subsequent periods

relating to a previous period can be material to our retail energy segment's and our consolidated results of operations.

In 2002 and 2003, a portion of our energy supply costs ($61 million and $53 million, respectively) consisted of estimated transmission and distribution charges not billed by the transmission and distribution utilities.

In estimating supply volumes, we consider the effects of historical customer volumes, weather factors and usage by customer class. We estimate our transmission and distribution delivery fees using the same method that we use for electricity sales and services to retail customers. In addition, we estimate ERCOT ISO fees based on historical trends, estimated supply volumes and initial ERCOT ISO settlements. Volume estimates are then multiplied by the estimated rate and recorded as purchased power expense in the applicable reporting period. If our estimate of electricity usage volumes increased or decreased by 3%, our energy supply costs would have increased or decreased by approximately $6 million. Changes in our volume usage would have resulted in a similar offsetting change in billed volumes, thus partially mitigating our energy supply costs.

Changes in Estimates. During 2003, we revised our estimates and assumptions related to retail energy revenues and energy supply costs in 2002. The revisions resulted in the recognition in 2003 of $39 million of income. As additional information becomes available, we may recognize additional income or losses.

Dependence on ERCOT ISO Settlement Procedures. In Texas, our primary retail energy market, the ERCOT ISO is responsible for scheduling and settling all electricity volumes and related fees. As part of settlement, the ERCOT ISO communicates actual volumes compared to scheduled volumes. The ERCOT ISO calculates an additional charge or credit by calculating the difference between the actual and scheduled volumes multiplied by the market-clearing price for balancing energy service. The ERCOT ISO also charges customer-serving market participants' administrative fees; reliability must run contract fees; out of merit energy fees and out of merit capacity fees. The ERCOT ISO allocates these and other fees to market participants based on each market participant's share of the total load. We may not know about these fees, which are generally outside of our control, until the ERCOT ISO bills them. If the ERCOT ISO's records indicate that our volumes delivered were greater than the volumes our records indicate, we may be billed a larger than expected share of these total fees.

Preliminary settlement information is due from the ERCOT ISO within two months after electricity is delivered. Final settlement information is due from the ERCOT ISO within 12 months after electricity is delivered. We record our estimated supply costs and related fees using estimated supply volumes, as discussed above, and adjust those costs upon receipt of the ERCOT ISO information. Delays in settlements could materially affect the accuracy of our recorded energy supply costs and related fees.

The ERCOT ISO volume settlement process has been delayed on several occasions because of operational problems with data management among the ERCOT ISO, the transmission and distribution utilities and the retail electric providers. During the third quarter of 2002, the ERCOT ISO issued true-up settlements for the pilot time period of July 2001 to December 2001. The ERCOT ISO then temporarily suspended true-up settlement calculations to allow a threshold level of consumption data for subsequent periods from the transmission and distribution utilities to be loaded into the ERCOT ISO's systems. In 2003, the ERCOT ISO prepared true-up settlement calculations for the period January 2002 through December 2002. The ERCOT ISO has scheduled to resume true-up settlement calculations for 2003 in April 2004.

These settlement calculations indicate that our customers utilized greater volumes of electricity than our records indicated. We have invoked the ERCOT ISO's dispute resolution process for settlement calculations for the period from January 2002 to date. As of December 31, 2003, the amount in dispute with the ERCOT ISO is $11 million due to differences in volumes partially offset by unaccounted-for-energy costs variances.

Loss Contingencies.

We record a loss contingency when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of those matters that can be estimated. We consider these estimates to be critical accounting estimates because (a) they entail significant judgment by us regarding probabilities and ranges of exposure, (b) the ultimate outcome of the proceedings relating to these contingencies is unknown and (c) the ultimate outcome could have a material adverse effect on our results of operations, financial condition and cash flows. Estimates of contingent losses affect all our reportable segments. For a discussion of these contingencies, see note 15 to our consolidated financial statements.

Deferred Tax Assets Valuation Allowance and Tax Liabilities.

We estimate (a) income taxes in each of the jurisdictions in which we operate, (b) net deferred tax assets based on expected future taxable benefits in such jurisdictions and (c) valuation allowance for deferred tax assets. For additional information regarding these estimates, which affect all of our reportable segments, see note 13 to our consolidated financial statements. We consider these estimates to be a critical accounting estimate because (a) they require estimates of projected future operating results (which are inherently imprecise) and (b) they depend on assumptions regarding our ability to generate future taxable income during the periods in which temporary differences are deductible.

In addition, we recognize contingent tax liabilities through tax expense and tax expense for discontinued operations for estimated exposures related to our current tax positions. We evaluate the need for contingent tax liabilities on a quarterly basis and any change in the amount will be recorded in our results of operations, as appropriate. It could take several years to resolve certain of these contingencies.

Related Party Transactions

For a discussion of related party transactions, see notes 3 and 4 to our consolidated financial statements.

Item 7A. ***Quantitative and Qualitative Disclosures about Non-Trading and Trading Activities and Related Market Risks.***

Market Risk and Risk Management

We are exposed to various market risks. These risks arise from the ownership of our assets and operation of our business. Most of the revenues, expenses, results of operations and cash flows from our business activities are impacted by market risks. Categories of significant market risks include exposures primarily related to commodity prices and interest rates.

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. We frequently utilize derivative instruments to execute our risk management and hedging strategies. Derivative instruments are instruments, such as futures, forward contracts, swaps or options that 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.

We primarily use derivative instruments to manage and hedge exposures, such as exposure to changes in electricity and fuel prices and interest rate risk on our floating-rate borrowings. 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 hedging strategy.

During 2002, we evaluated our trading, marketing, power origination and risk management services strategies and activities. During the second half of 2002, we began to reduce our wholesale energy segment's trading. In March 2003, we discontinued our proprietary trading business. Trading positions taken prior to our decision to exit this business are managed solely for purposes of closing them on economical terms.

We have a risk control framework designed to monitor, measure and define appropriate transactions to hedge and manage the risk in our existing portfolio of assets and contracts and to authorize new transactions. These risks fall into three different categories: market risk, credit risk and operational risk. We believe that we have effective procedures for evaluating and managing these risks to which we are exposed. Key risk control activities include definition of appropriate transactions for hedging, 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, value-at-risk 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.

The effectiveness of our policies and procedures for managing risk exposure can never be completely estimated or fully assured. For example, we could experience losses, which could have a material adverse effect on our results of operations, financial condition or cash flows from unexpectedly large or rapid movements or disruptions in the energy markets, from regulatory-driven market rule changes and/or bankruptcy of customers or counterparties.

Given our current credit and liquidity situation and other factors, we have reduced our hedging activities, which could result in greater volatility in future earnings. Additionally, the reduction in market liquidity may impair the effectiveness of our risk management procedures and hedging strategies. These and other factors may adversely impact our results of operations, financial condition and cash flows.

See notes 2(d) and 7 to our consolidated financial statements for the accounting for these types of transactions.

Non-trading Market Risk

Commodity Price Risk. Commodity price risk is an inherent component of wholesale and retail electric businesses. Prior to the energy delivery period, we attempt to hedge, in part, the economics of our

wholesale and retail electric businesses. Derivative instruments are used to mitigate exposure to variability in future cash flows from probable, anticipated future transactions attributable to a commodity risk.

The following table sets forth the fair values of the contracts related to our net non-trading derivative assets and liabilities as of December 31, 2003:

	Fair Value of Contracts at December 31, 2003						
Source of Fair Value	2004	2005	2006	2007	2008	2009 and thereafter	Total fair value
	(In millions)						
Prices actively quoted(1)	$ 1	$(8)	$ —	$ —	$ —	$ —	$ (7)
Prices provided by other external sources(2)	103	24	3	(1)	—	—	129
Prices based on models and other valuation methods(3)	51	—	(19)	(10)	(6)	(17)	(1)
Total	$155	$16	$(16)	$(11)	$ (6)	$(17)	$121

(1) Represents our NYMEX futures positions in natural gas and crude oil. NYMEX has quoted prices for natural gas and crude oil for the next 72 and 30 months, respectively.

(2) Represents our forward positions in natural gas and power at points for which OTC broker quotes are available, which on average, extend 36 and 24 months into the future, respectively. Positions are valued against internally developed forward market price curves that are frequently validated 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.

(3) Represents the value of (a) our valuation adjustments for liquidity, credit and administrative costs, (b) options or structured transactions not quoted by an exchange or OTC broker, but for which the prices of the underlying are available and (c) 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.

The fair values in the above table are subject to significant changes based on fluctuating market prices and conditions. Changes in our derivative assets and liabilities result primarily from changes in the valuation of the portfolio of contracts and the timing of settlements. The most significant parameters impacting the value of our portfolios of contracts include natural gas and power forward market prices, volatility and credit risk. 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.

We assess the risk of our non-trading derivatives using a sensitivity analysis method. Derivative instruments, which we use as economic hedges, create exposure to commodity prices, which, in turn, 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. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in fair value based on a hypothetical 10% movement in the underlying energy prices. A decrease of 10% in the market prices of energy commodities from their December 31, 2003 levels would have decreased the fair value of our non-trading energy derivatives by $70 million. Of this amount, $63 million relates to a loss in fair value of our non-trading derivatives that are designated as cash flow hedges and $7 million relates to a loss in earnings of our economic hedges. A decrease of 10% in the market prices of energy commodities from their December 31, 2002 levels would have decreased the fair value of our non-trading energy derivatives by $38 million.

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 is managed to complement our asset portfolio, thereby reducing overall risks. 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, which qualify as cash flow hedges, and which are effective as hedges, may still have some percentage that is not effective. The change in value of the non-trading energy derivatives, which represents the ineffective component of the cash flow hedges, is recorded in our results of operations. During 2001, 2002 and 2003, we recognized a gain of $28 million, a loss of $17 million and a loss of $20 million, respectively, in our results of operations due to hedge ineffectiveness.

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. In addition, we have entered into interest rate swap and interest rate cap agreements to mitigate our exposure to interest rate fluctuations associated with certain of our variable rate debt instruments. We assess interest rate risks using a sensitivity analysis method. The table below provides information concerning our financial instruments as of December 31, 2002 and 2003, that are sensitive to changes in interest rates:

	Aggregate Notional Amount	Fair Market Value/Swap Termination Value(1)	Hypothetical Change in Underlying at End of Period	Financial Impact
	(In millions)			
December 31, 2002:				
Floating rate debt(2)(3)	$5,936	N/A(4)	10% increase	$2 million increased monthly interest expense
Fixed rate debt(3)	560	$ 409	10% decrease	$31 million increase in fair market value
Interest rate swaps(5):				
Orion Midwest	600	(69)	10% decrease	$4 million increase in termination cost
Orion NY	250	(45)	10% decrease	$4 million increase in termination cost
Channelview	200	(18)	10% decrease	$1 million increase in termination cost
December 31, 2003:				
Floating rate debt(2)(3)	$3,910	$3,850	10% increase	$1 million increased monthly interest expense
Fixed rate debt(3)	1,921	1,992	10% decrease	$91 million increase in fair market value
Interest rate swaps(5):				
Orion Midwest	300	(48)	10% decrease	$3 million increase in termination cost
Orion NY	250	(36)	10% decrease	$3 million increase in termination cost
Channelview	200	(13)	10% decrease	$1 million increase in termination cost
Interest rate caps	4,500	4	10% decrease	$1 million loss in earnings

(1) See note 18 to our consolidated financial statements for further discussion on the fair market value of our financial instruments.

(2) Excludes adjustment to fair value of our interest rate swaps.

(3) Excludes Liberty's debt.

(4) As of December 31, 2002, we had floating rate debt with a carrying value of $5.9 billion, excluding adjustment to fair value of interest rate swaps and Liberty's debt. There was no active market for our floating rate debt obligations as of December 31, 2002.

(5) These derivative instruments qualify for hedge accounting under SFAS No. 133 and the periodic settlements are recognized as an adjustment to interest expense in our results of operations over the term of the related agreement. As of December 31, 2002 and 2003, these swaps have negative termination values (i.e., we would have to pay). See note 9(c) to our consolidated financial statements.

Trading Market Risk

In our results of operations, historically, our trading activities included (a) transactions establishing open positions in the energy markets, primarily on a short-term basis and (b) energy price risk management services to customers primarily related to natural gas, electric power and other energy-related commodities. We provided these services by utilizing a variety of derivative instruments. We accounted for these transactions under mark-to-market accounting and continue to account for the remaining legacy positions under mark-to-market accounting. Our electricity sales to large commercial, industrial and institutional customers under contracts executed before October 25, 2002 were accounted for under the mark-to-market method of accounting upon contract execution. For further discussion of these activities, see notes 2(d) and 7 to our consolidated financial statements.

The following table sets forth our consolidated net trading assets (liabilities) by segment as of December 31, 2002 and 2003:

	As of December 31,	
	2002	2003
	(In millions)	
Retail energy	$ 94	$ —
Wholesale energy	105	(1)
Net trading assets and liabilities	$199	$ (1)

The following table sets forth the fair values of the contracts related to our legacy net trading assets and liabilities as of December 31, 2003:

	Fair Value of Contracts at December 31, 2003						
Source of Fair Value	2004	2005	2006	2007	2008	2009 and thereafter	Total fair value
	(In millions)						
Prices actively quoted	$(34)	$ 9	$2	$—	$—	$—	$(23)
Prices provided by other external sources	13	(22)	4	1	2	2	—
Prices based on models and other valuation methods	2	3	(5)	7	11	4	22
Total	$(19)	$(10)	$1	$ 8	$13	$ 6	$ (1)

For information regarding "prices actively quoted," "prices provided by other external sources" and "prices based on models and other valuation methods," see discussion above related to non-trading derivative assets and liabilities.

The fair values in the above table are subject to significant changes based on fluctuating market prices and conditions. For further discussion of items resulting in changes in the valuation of the portfolio of trading contracts, see discussion above related to non-trading derivative assets and liabilities.

The following table sets forth our consolidated realized and unrealized trading margins for 2001, 2002 and 2003:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Realized	$182	$311	$(25)
Unrealized	196	(23)	(24)
Total	$378	$288	$(49)

Below is an analysis of our net consolidated trading assets and liabilities for 2001, 2002 and 2003.

	Year Ended December 31,	
	2002	2003
	(In millions)	
Fair value of contracts outstanding, beginning of period	$227	$199
Net assets transferred to non-trading derivatives due to implementation of EITF No. 02-03(1)	—	(93)
Other net assets transferred to non-trading derivatives(1)	—	(18)
Net assets recorded to cumulative effect under EITF No. 02-03(1)	—	(63)
Fair value of new contracts upon execution	57	—
Contracts realized or settled	(311)	25
Changes in fair values attributable to changes in valuation techniques and assumptions	31	11
Changes in fair values attributable to market price and other market changes	195	(62)
Fair value of contracts outstanding, end of period	$199	$ (1)

(1) See note 2(d) to our consolidated financial statements.

Fair Value of New Contracts — General. The fair value of retail energy segment electric sales contracts with large commercial, industrial and institutional customers was determined by comparing the contract price to an estimate of the market cost of delivered retail energy and applying the estimated volumes under the provisions of these contracts. The calculation of the estimated cost of energy involves estimating the customer's anticipated load volume, and using forward ERCOT OTC commodity prices, adjusted for the customer's anticipated load characteristics. The delivery costs were estimated at the time sales contracts were executed. These costs were based on published rates and our experience of actual delivery costs. The fair values of these energy supply contracts were estimated using ERCOT OTC forward price and volatility curves and correlations among power and fuel prices specific to the ERCOT Region, net of credit risk. The fair values of new 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.

Fair Value of New Contracts — 2002. During 2002, our retail energy segment entered into electric sales contracts with large commercial, industrial and institutional customers ranging from one-half to four years in duration. During 2002, we recognized total fair value of $43 million for these contracts at the inception dates. We entered into energy supply contracts to substantially hedge the economics of these contracts. These contracts had an aggregate fair value of $8 million at the contract inception dates. The remaining fair value of contracts entered into during 2002 recorded at inception of $6 million primarily relates to natural gas transportation contracts entered into by our wholesale energy segment.

Changes in Fair Values Attributable to Changes in Valuation Techniques and Assumptions — 2002. During 2002, the following changes in valuation techniques and assumptions were made:

- We changed our methodology for allocating credit reserves between our trading and non-trading portfolios. Total credit reserves calculated for both the trading and non-trading portfolios, which are less than the sum of the independently calculated credit reserves for each portfolio due to common counterparties between the portfolios, are allocated to the trading and non-trading portfolios based upon the independently calculated trading and non-trading credit reserves. Previously, credit reserves were independently calculated for the trading portfolio while credit reserves for the non-trading portfolio were calculated by deducting the trading credit reserves from the total credit reserves calculated for both portfolios. This change in methodology reduced credit reserves relating to the trading portfolio by $18 million.
- Our retail energy segment eliminated a valuation factor for potential claims for delays in switching under the liquidated damages clauses in contracts. We eliminated this valuation factor because there was adequate data to substantiate that these claims would not be submitted. This change in methodology reduced credit reserves by $5 million.
- Our retail energy segment added a valuation factor adjustment to capture the potential earnings loss associated with customers terminating contracts due to a provision in some of its contracts that allows customers to terminate their contracts if our unsecured debt ratings fall below investment grade or if our ratings are withdrawn entirely by a rating agency. During 2002, each of the major rating agencies downgraded our credit ratings to sub-investment grade. We performed an analysis at the customer level to estimate our exposure for these provisions. This change in methodology increased credit reserves by $1 million.
- Our retail energy segment changed the methodology related to recording its estimate of unaccounted-for-energy. Our retail energy segment changed its unaccounted-for-energy factor from 1.6% to zero. The reason for the change is that we believed the unaccounted-for-energy factor was effectively included in the volatility valuation factor and our results from energy sales in 2001 were not negatively impacted by unaccounted-for-energy. This change in methodology increased the fair value of the net trading assets by $9 million.

Changes in Fair Values Attributable to Changes in Valuation Techniques and Assumptions — 2003. During 2003, the following changes in valuation techniques and assumptions were made:

- We modified our estimated probabilities of counterparty default and considered master netting agreements, which resulted in a decrease in credit reserves of $10 million.
- We reduced estimated costs to administer transactions used in calculating administrative reserves to reflect the change in our cost structure, which resulted in a decrease in administrative reserves of $2 million.
- We modified our assumptions for liquidity reserves to consider the widening of bid/ask spreads for transactions occurring further into the future, which resulted in an increase in the liquidity reserves of $5 million.
- We adjusted our discount rate used in valuing derivative transactions to a risk-free United States treasury rate from an investment-grade utility rate, which resulted in an increase in fair value of $4 million.

We employ a risk management system to mitigate the risks associated with our legacy trading activities. These activities involve market risk associated with managing these energy commodities. Historically, our trading activities depended on price and volatility changes to create business opportunities, but within authorized limits.

We primarily assess the risk of our legacy trading positions using a value-at-risk method, in order to maintain our total exposure within authorized limits. Value-at-risk 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 parametric variance/covariance method with delta/gamma approximation to calculate value-at-risk.

Our value-at-risk limits are set by the audit committee of our board of directors. Risk limits for our legacy trading activities include both value-at-risk as well as other non-statistical measures of portfolio exposure. The risk management process supplements the measurement and enforcement of the limit metrics with additional analyses including stress testing the portfolio for extreme events and back-testing the value-at-risk model.

Our value-at-risk model utilizes four major parameters: confidence level, volatility, correlation and holding period.

- Confidence level: Natural gas and petroleum products have a confidence interval of 95% and power products have a confidence interval of 99%. The confidence level for power products is higher in order to capture the non-normality of power price behavior.
- Volatility: Calculated daily from historical forward prices using the exponentially weighted moving average method.
- Correlation: Calculated daily from daily volatilities and historical forward prices using the exponentially weighted moving average method. This parameter is included to account for the diversification of the portfolio.
- Holding period: Natural gas and petroleum products generally have one day holding periods for 2002 and two day holding periods for 2003. Power products have holding periods of 1 to 20 days for 2002 and 5 to 20 days for 2003 based on the risk profile of the portfolio. The holding periods for power products reflect our efforts to appropriately account for possible liquidation periods of more than one or five days, as applicable, which is reasonable for some non-standard products. The change in assumptions for the holding periods for natural gas and petroleum products and power products in 2003 did not have a material impact on the value-at-risk calculation.

Assuming a confidence level of 95% and a one-day holding period, if value-at-risk 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 applicable portfolio in a one-day period would exceed $10 million.

While we believe that our assumptions and approximations are reasonable for calculating value-at-risk, there is no uniform industry methodology for estimating value-at-risk, and different assumptions and/or approximations could produce materially different value-at-risk estimates.

An inherent limitation of value-at-risk is that past market risk may not produce accurate predictions of future market risk. Moreover, value-at-risk calculated for a specified holding period does not fully capture the market risk of positions that cannot be liquidated or offset with hedges within that specified period. Future transactions, market volatility, reduction of market liquidity, failure of counterparties to satisfy their contractual obligations and/or a failure of risk controls could result in material losses from our legacy trading activities.

The following table presents the daily value-at-risk for substantially all of our legacy trading positions for our continuing operations for 2002 and 2003:

	2002	2003
	(In millions)	
As of December 31	$17	$7
Year Ended December 31:		
Average	17	7
High	29	35
Low	10	2

During 2003, average value-at-risk exposure was lower compared to 2002 due to certain power trading activities in ERCOT related to our retail energy segment no longer being accounted for on a mark-to-market method of accounting. See note 2(d) to our consolidated financial statements. Lower overall trading volumes during 2003 due to discontinuing proprietary trading activities also contributed to a reduction in value-at-risk. There was a short-term increase in value-at-risk during February 2003 due to volatility in the natural gas market. As a result and prior to exiting proprietary trading activities, we realized a trading loss related to certain of our natural gas trading positions of approximately $80 million pre-tax in the first quarter of 2003.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. Credit risk is inherent in our commercial activities. See note 7(c) to our consolidated financial statements for a discussion of our credit risk and policies.

The following table includes: trading and derivative assets, accounts receivable, after taking into consideration netting within each contract and any master netting contracts with counterparties, as of December 31, 2003:

Credit Rating Equivalent	Exposures Before Collateral	Credit Collateral Held(1)	Exposure Net of Collateral	Number of Counterparties > 10%	Net Exposure of Counterparties >10%
			(In millions)		
Investment grade	$310	$—	$310	—	$ —
Non-investment grade	35	9	26	—	—
No external ratings(2):					
Internally rated — Investment grade	78	—	78	—	—
Internally rated — Non-investment grade	208	—	208	1	113
Total	$631	$ 9	$622	1	$113

(1) Collateral consists of cash and standby letters of credit.

(2) For unrated counterparties, we perform credit analyses, considering contractual rights and restrictions, and credit support such as parent company guarantees to create an internal credit rating.

Trading and derivative assets and accounts receivable are presented separately in our consolidated balance sheets. The trading and derivative assets and accounts receivable are set-off separately in our consolidated balance sheets although in most cases contracts permit the set-off of trading and derivative assets and accounts receivable with a given counterparty. For the purpose of disclosing the credit risk, all assets and liabilities with a given counterparty were set-off if the counterparty has entered into a contract with us that permits such set-off.

The above table excludes amounts related to contracts classified as "normal" in accordance with SFAS No. 133 and non-derivative contractual commitments that are not recorded in our consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit risk and economic risk in the case of nonperformance by a counterparty. Nonperformance by counterparties under these contractual commitments could have a material adverse impact on our future results of operations, financial condition and cash flows.

For information regarding credit risk related to one counterparty representing more than 10% of our total credit exposure, see note 7(c) to our consolidated financial statements.

* * *

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

INDEX TO FINANCIAL STATEMENTS

RELIANT RESOURCES, INC. AND SUBSIDIARIES

Responsibility for Financial Reporting	F-2
Independent Auditors' Report	F-3
Consolidated Statements of Operations for the Years Ended December 31, 2001, 2002 and 2003	F-4
Consolidated Balance Sheets as of December 31, 2002 and 2003	F-5
Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2002 and 2003	F-6
Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2001, 2002 and 2003	F-7
Notes to Consolidated Financial Statements	F-10
Supplementary Data	F-107

RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying consolidated financial statements of Reliant Resources, Inc. and subsidiaries were prepared by management, which is responsible for their integrity and objectivity. The statements were prepared in accordance with accounting principles generally accepted in the United States of America and include amounts that are based on management's best judgments and estimates.

Reliant Resources, Inc.'s system of internal controls is designed to provide reasonable assurance as to the reliability of financial records and reporting and the protection of assets. The system of controls provides for appropriate division of responsibility and the application of policies and procedures that are consistent with applicable standards of accounting and administration. Internal controls are monitored through recurring internal audit programs and are updated as our businesses and business conditions change.

The Audit Committee, composed solely of outside directors, determines that management is fulfilling its financial responsibilities by meeting periodically with management, the independent auditors and Reliant Resources, Inc.'s internal auditors, to review internal accounting control and assess the effectiveness of our disclosure controls and procedures. The Audit Committee is responsible for appointing the independent auditors and reviewing the scope of all audits and the accounting principles applied in our financial reporting. Deloitte & Touche LLP has been engaged as independent auditors to audit the accompanying consolidated financial statements and issue their report thereon, which appears on the following page.

To ensure complete independence, our internal auditors and Deloitte & Touche LLP have full and free access to meet with the Audit Committee, without management present, to discuss the results of their audits, the quality of our financial reporting and the adequacy of our internal controls and disclosure controls and procedures.

We believe that Reliant Resources, Inc.'s system of internal controls, combined with the activities of the internal auditors and the Audit Committee, provides reasonable assurance of the integrity of our financial reporting.

/s/ Joel V. Staff	/s/ Mark M. Jacobs
Joel V. Staff Chairman and Chief Executive Officer	Mark M. Jacobs Executive Vice President and Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Reliant Resources, Inc. and Subsidiaries
Houston, Texas

We have audited the accompanying consolidated balance sheets of Reliant Resources, Inc. and subsidiaries (the "Company"), as of December 31, 2002 and 2003, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedules (Schedule I and Schedule II) listed in the Index at Item 15(a)(2). These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in notes 2, 6 and 7 to the consolidated financial statements, the Company changed its accounting for asset retirement obligations, energy trading contracts, consolidation of variable interest entities and its presentation of revenues and costs of sales associated with non-trading commodity derivative activities in 2003; its method of presenting trading and marketing activities from a gross to a net basis and its accounting for goodwill and other intangibles in 2002; and its accounting for derivative contracts and hedging activities in 2001.

DELOITTE & TOUCHE LLP

Houston, Texas
March 5, 2004

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(Thousands of Dollars, except per share amounts)

	Year Ended December 31,		
	2001	2002	2003
Revenues:			
Revenues	$5,498,795	$10,588,122	$11,049,323
Trading margins	378,523	288,088	(49,004)
Total	5,877,318	10,876,210	11,000,319
Expenses:			
Fuel and cost of gas sold	1,575,588	1,081,668	1,414,182
Purchased power	2,498,320	7,420,659	7,031,063
Accrual for payment to CenterPoint Energy, Inc.	—	128,300	46,700
Operation and maintenance	460,559	784,989	864,542
General, administrative and development	471,664	630,035	552,803
Wholesale energy goodwill impairment	—	—	985,000
Depreciation	101,331	316,917	359,621
Amortization	68,700	50,858	58,942
Total	5,176,162	10,413,426	11,312,853
Operating Income (Loss)	701,156	462,784	(312,534)
Other Income (Expense):			
Gains (losses) from investments, net	22,864	(23,100)	1,844
Income (loss) of equity investments	6,771	17,836	(1,652)
Loss on sale of receivables	—	(10,347)	(37,613)
Other, net	2,171	16,324	9,298
Interest expense	(16,152)	(266,962)	(516,729)
Interest income	22,207	28,023	35,311
Interest income — affiliated companies, net	12,481	4,754	—
Total other income (expense)	50,342	(233,472)	(509,541)
Income (Loss) from Continuing Operations Before Income Taxes	751,498	229,312	(822,075)
Income tax expense	290,883	106,006	80,082
Income (Loss) from Continuing Operations	460,615	123,306	(902,157)
Income (loss) from discontinued operations before income taxes	83,184	(341,418)	(310,047)
Income tax (benefit) expense	(16,490)	108,100	105,858
Income (loss) from discontinued operations	99,674	(449,518)	(415,905)
Income (Loss) Before Cumulative Effect of Accounting Changes	560,289	(326,212)	(1,318,062)
Cumulative effect of accounting changes, net of tax	3,062	(233,600)	(24,055)
Net Income (Loss)	$ 563,351	$ (559,812)	$(1,342,117)
Basic Earnings (Loss) per Share:			
Income (loss) from continuing operations	$ 1.66	$ 0.43	$ (3.07)
Income (loss) from discontinued operations, net of tax	0.36	(1.55)	(1.42)
Income (loss) before cumulative effect of accounting changes	2.02	(1.12)	(4.49)
Cumulative effect of accounting changes, net of tax	0.01	(0.81)	(0.08)
Net income (loss)	$ 2.03	$ (1.93)	$ (4.57)
Diluted Earnings (Loss) per Share:			
Income (loss) from continuing operations	$ 1.66	$ 0.42	$ (3.07)
Income (loss) from discontinued operations, net of tax	0.36	(1.54)	(1.42)
Income (loss) before cumulative effect of accounting changes	2.02	(1.12)	(4.49)
Cumulative effect of accounting changes, net of tax	0.01	(0.80)	(0.08)
Net income (loss)	$ 2.03	$ (1.92)	$ (4.57)

See Notes to our Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)

	December 31, 2002	December 31, 2003
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,114,850	$ 146,524
Restricted cash	212,595	250,748
Accounts and notes receivable, principally customer, net	1,173,957	801,468
Notes receivable related to receivables facility	167,996	393,822
Inventory	274,666	268,701
Trading and derivative assets	666,840	493,046
Margin deposits on energy trading and hedging activities	312,641	77,271
Accumulated deferred income taxes	58,335	96,545
Prepayments and other current assets	143,199	161,145
Current assets of discontinued operations	663,862	—
Total current assets	4,788,941	2,689,270
Property, Plant and Equipment, net	6,991,379	8,526,784
Other Assets:		
Goodwill, net	1,540,506	482,534
Other intangibles, net	736,689	719,469
Equity investments	103,199	95,223
Trading and derivative assets	263,905	199,716
Accumulated deferred income taxes	3,430	6,039
Prepaid lease	200,052	217,781
Restricted cash	7,000	36,916
Other	206,638	334,527
Long-term assets of discontinued operations	2,378,427	—
Total other assets	5,439,846	2,092,205
Total Assets	$17,220,166	$13,308,259
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and short-term borrowings	$ 819,690	$ 430,685
Accounts payable, principally trade	755,267	516,843
Trading and derivative liabilities	516,914	357,219
Margin deposits from customers on energy trading and hedging activities	50,203	36,136
Retail customer deposits	51,750	57,279
Accumulated deferred income taxes	18,394	2
Accrual for payment to CenterPoint Energy, Inc.	—	175,000
Other	310,279	425,245
Current liabilities of discontinued operations	1,087,808	—
Total current liabilities	3,610,305	1,998,409
Other Liabilities:		
Accumulated deferred income taxes	393,495	524,701
Trading and derivative liabilities	260,437	216,399
Accrual for payment to CenterPoint Energy, Inc.	128,300	—
Benefit obligations	113,015	133,664
Other	293,398	354,176
Long-term liabilities of discontinued operations	759,818	—
Total other liabilities	1,948,463	1,228,940
Long-term Debt	6,008,510	5,709,111
Commitments and Contingencies Stockholders' Equity:		
Preferred stock; par value $0.001 per share (125,000,000 shares authorized; none outstanding)	—	—
Common stock; par value $0.001 per share (2,000,000,000 shares authorized; 299,804,000 issued)	61	61
Additional paid-in capital	5,836,957	5,841,438
Treasury stock at cost, 9,198,766 and 5,212,017 shares	(158,483)	(89,769)
Retained earnings (deficit)	3,539	(1,338,578)
Accumulated other comprehensive loss	(67,692)	(41,353)
Accumulated other comprehensive income from discontinued operations	38,506	—
Stockholders' equity	5,652,888	4,371,799
Total Liabilities and Stockholders' Equity	$17,220,166	$13,308,259

See Notes to our Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of Dollars)

	Year Ended December 31,		
	2001	2002	2003
Cash Flows from Operating Activities:			
Net income (loss)	$ 563,351	$ (559,812)	$(1,342,117)
(Income) loss from discontinued operations	(99,674)	449,518	415,905
Net income (loss) from continuing operations and cumulative effect of accounting changes	463,677	(110,294)	(926,212)
Adjustments to reconcile net income (loss) to net cash (used in) provided by operating activities:			
Cumulative effect of accounting changes	(3,062)	233,600	24,055
Wholesale energy goodwill impairment	—	—	985,000
Impairment of marketable equity securities and other investments	—	31,780	—
Depreciation and amortization	170,031	367,775	418,563
Deferred income taxes	35,327	133,962	59,743
Net trading and derivative assets and liabilities	(168,765)	(7,839)	68,156
Net amortization of contractual rights and obligations	—	(3,306)	(5,449)
Amortization of deferred financing costs	591	2,786	104,921
Undistributed earnings of unconsolidated subsidiaries	20,388	(14,861)	1,652
Accrual for payment to CenterPoint Energy, Inc.	—	128,300	46,700
Curtailment and related benefit enhancement	99,523	—	—
Accounting settlement for certain benefit plans	—	47,356	4,661
Other, net	(5,641)	(21,157)	(7,931)
Changes in other assets and liabilities:			
Restricted cash	(117,421)	281,755	(68,069)
Accounts and notes receivable and unbilled revenue, net	809,374	(135,980)	98,126
Notes receivable facility proceeds, net	—	95,000	23,000
Accounts receivable/payable — formerly affiliated companies, net	94,237	26,721	—
Inventory	(58,333)	(73,582)	11,663
Collateral for electric generating equipment, net	(145,090)	136,013	—
Margin deposits on energy trading and hedging activities, net	167,374	(193,411)	221,303
Net non-trading derivative assets and liabilities	(117,858)	86,462	(72,712)
Prepaid lease obligation	(180,531)	(78,551)	(17,727)
Other current assets	109,314	(31,456)	(20,599)
Other assets	(44,492)	(28,833)	(87,972)
Accounts payable	(1,112,433)	(239,026)	(191,203)
Taxes payable/receivable	(40,330)	(19,925)	55,778
Other current liabilities	18,007	(3,537)	77,546
Other liabilities	49,958	(66,704)	39,207
Net cash provided by continuing operations from operating activities	43,845	543,048	842,200
Net cash (used in) provided by discontinued operations from operating activities	(196,343)	(23,335)	27,153
Net cash (used in) provided by operating activities	(152,498)	519,713	869,353
Cash Flows from Investing Activities:			
Capital expenditures	(727,788)	(640,475)	(587,021)
Business acquisition, net of cash acquired	—	(2,963,801)	—
Other, net	1,844	(704)	7,560
Net cash used in continuing operations from investing activities	(725,944)	(3,604,980)	(579,461)
Net cash (used in) provided by discontinued operations from investing activities	(112,125)	118,802	1,621,352
Net cash (used in) provided by investing activities	(838,069)	(3,486,178)	1,041,891
Cash Flows from Financing Activities:			
Proceeds from long-term debt	—	13,537	1,612,120
Proceeds from issuance of stock, net	1,696,074	—	—
Payments of long-term debt	(9)	(204,354)	(2,165,219)
Increase (decrease) in short-term borrowings and revolving credit facilities, net	128,874	4,066,338	(1,425,140)
Change in notes with formerly affiliated companies, net	(731,894)	385,652	—
Purchase of treasury stock	(189,460)	—	—
Proceeds from issuances of treasury stock	—	13,527	7,531
Contributions from CenterPoint	9,441	—	—
Payments of financing costs	(1,330)	(43,209)	(183,865)
Other, net	3,096	(597)	—
Net cash provided by (used in) continuing operations from financing activities	914,792	4,230,894	(2,154,573)
Net cash provided by (used in) discontinued operations from financing activities	84,748	(250,168)	(734,068)
Net cash provided by (used in) financing activities	999,540	3,980,726	(2,888,641)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(5,752)	3,009	9,071
Net Change in Cash and Cash Equivalents	3,221	1,017,270	(968,326)
Cash and Cash Equivalents at Beginning of Period	94,359	97,580	1,114,850
Cash and Cash Equivalents at End of Period	$ 97,580	$ 1,114,850	$ 146,524
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest paid (net of amounts capitalized) for continuing operations	$ 44,541	$ 258,339	$ 413,554
Income taxes paid (net of income tax refunds received) for continuing operations	243,740	10,027	(74,917)

See Notes to our Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(Thousands of Dollars)

	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized (Loss) Gain on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive (Loss) Income	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Balance December 31, 2000	$ 1	$2,349,693	$ —	$ —	$(2,264)	$ —	$ —	$ (716)	$ (2,980)	$ (1,564)	$2,345,150	
Net income				563,351							563,351	$ 563,351
Contributions from CenterPoint		1,787,311									1,787,311	
Purchases of treasury stock			(189,460)								(189,460)	
Majority owner effect of treasury stock purchases		(43,149)									(43,149)	
IPO proceeds, net	60	1,696,014									1,696,074	
Other comprehensive income (loss):												
Foreign currency translation adjustments, net of tax of $0 and $98 million							(679)		(679)	(93,387)	(94,066)	(679)
Changes in minimum pension liability, net of tax of $4 million								(6,799)	(6,799)		(6,799)	(6,799)
Cumulative effect of adoption of SFAS No. 133, net of tax of $236 million and $0						(439,044)			(439,044)	(20,900)	(459,944)	(439,044)
Deferred gain from cash flow hedges, net of tax of $228 million and $0						413,463			413,463	14,531	427,994	413,463
Reclassification of net deferred gain/loss from cash flow hedges into net income, net of tax of $35 million and $0						(60,571)			(60,571)	9,427	(51,144)	(60,571)
Unrealized gain on available-for-sale securities, net of tax of $9 million					16,984				16,984		16,984	16,984
Reclassification adjustments for gains on sales of available-for-sale securities realized in net income, net of tax of $5 million					(8,670)				(8,670)		(8,670)	(8,670)
Other comprehensive loss from discontinued operations												(90,329)
Comprehensive income												$ 387,706
Balance December 31, 2001	$61	$5,789,869	$(189,460)	$563,351	$ 6,050	$ (86,152)	$ (679)	$(7,515)	$ (88,296)	$(91,893)	$5,983,632	

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS) — (Continued)
(Thousands of Dollars)

	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized (Loss) Gain on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive (Loss) Income	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Balance December 31, 2001	$61	$5,789,869	$(189,460)	$ 563,351	$ 6,050	$(86,152)	$ (679)	$(7,515)	$(88,296)	$(91,893)	$5,983,632	
Net loss				(559,812)							(559,812)	$(559,812)
Contributions from CenterPoint		52,811									52,811	
Transactions under stock plans		(5,723)	30,977								25,254	
Other comprehensive income (loss):												
Foreign currency translation adjustments, net of tax of $0 and $113 million							(845)		(845)	129,295	128,450	(845)
Changes in minimum pension liability, net of tax of $3 million								4,869	4,869		4,869	4,869
Deferred gain from cash flow hedges, net of tax of $22 million and $9 million						21,934			21,934	16,503	38,437	21,934
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $0 and $8 million						(420)			(420)	(15,399)	(15,819)	(420)
Unrealized loss on available-for-sale securities, net of tax of $1 million					(1,672)				(1,672)		(1,672)	(1,672)
Reclassification adjustments for gains on sales of available-for-sale securities realized in net loss, net of tax of $2 million					(3,262)				(3,262)		(3,262)	(3,262)
Other comprehensive income from discontinued operations												130,399
Comprehensive loss												$(408,809)
Balance December 31, 2002	$61	$5,836,957	$(158,483)	$ 3,539	$ 1,116	$(64,638)	$(1,524)	$(2,646)	$(67,692)	$ 38,506	$5,652,888	

RELIANT RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS) — (Continued)
(Thousands of Dollars)

	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Unrealized (Loss) Gain on Available For Sale Securities	Deferred Derivative Gains (Losses)	Foreign Currency Translation Adjustments	Additional Minimum Benefits Liability	Total Accumulated Other Comprehensive (Loss) Income	Discontinued Operations Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Balance December 31, 2002	$61	$5,836,957	$(158,483)	$ 3,539	$ 1,116	$ (64,638)	$(1,524)	$(2,646)	$ (67,692)	$38,506	$5,652,888	
Net loss				(1,342,117)							(1,342,117)	$(1,342,117)
Contributions from CenterPoint		45,498									45,498	
Issuance of warrants		14,360									14,360	
Transactions under stock plans		(55,377)	68,714								13,337	
Other comprehensive income (loss):												
Foreign currency translation adjustments, net of tax of $0 and $17 million							543		543	(34,343)	(33,800)	543
Changes in minimum pension liability, net of tax of $1 million								1,369	1,369		1,369	1,369
Deferred gain from cash flow hedges, net of tax of $37 million						61,299			61,299		61,299	61,299
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $36 million and $4 million						(35,758)			(35,758)	(4,163)	(39,921)	(35,758)
Unrealized loss on available-for-sale securities, net of tax of $0					(350)				(350)		(350)	(350)
Reclassification adjustments for gains on sales of available-for-sale securities realized in net loss, net of tax of $0					(764)				(764)		(764)	(764)
Other comprehensive loss from discontinued operations												(38,506)
Comprehensive loss												$(1,354,284)
Balance December 31, 2003	$61	$5,841,438	$ (89,769)	$(1,338,578)	$ 2	$ (39,097)	$ (981)	$(1,277)	$ (41,353)	$ —	$4,371,799	

See Notes to our Consolidated Financial Statements

RELIANT RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

"Reliant Resources" refers to Reliant Resources, Inc. and "we," "us" and "our" refer to Reliant Resources, Inc. and its consolidated subsidiaries, unless we specify or the context indicates otherwise.

Our business operations consist of two principal business segments:

- Retail energy — provides electricity and related services to retail customers primarily in Texas and acquires and manages the electric energy, capacity and ancillary services associated with supplying these retail customers; and
- Wholesale energy — provides electric energy, capacity and ancillary services in the competitive segments of the United States' wholesale energy markets.

Our remaining operations include unallocated corporate functions and minor equity and other investments.

Reliant Resources, Inc., a Delaware corporation, was incorporated in August 2000 with 1,000 shares of common stock which were owned by Reliant Energy, Incorporated (Reliant Energy). Reliant Energy adopted a business separation plan in response to the Texas Electric Choice Plan (Texas electric restructuring law) adopted by the Texas legislature in June 1999. The Texas electric restructuring law provided for retail electric competition beginning in January 2002. Under its business separation plan filed with the Public Utility Commission of Texas (PUCT), Reliant Energy transferred substantially all of its unregulated businesses to Reliant Resources in order to separate its regulated and unregulated operations. In accordance with the plan, in May 2001, Reliant Resources offered 59.8 million shares of its common stock to the public at an initial offering price of $30 per share (IPO) and received net proceeds from the IPO of $1.7 billion.

CenterPoint Energy, Inc. was formed on August 31, 2002 as the successor to Reliant Energy. Unless clearly indicated otherwise these references to "CenterPoint" mean CenterPoint Energy, Inc. on or after August 31, 2002 and Reliant Energy prior to August 31, 2002. CenterPoint is a regulated energy services and delivery company that owned the majority of Reliant Resources outstanding common stock prior to September 30, 2002. On September 30, 2002, CenterPoint distributed all of the 240 million shares of our common stock it owned to its common shareholders (Distribution). The Distribution completed the separation of Reliant Resources and CenterPoint into two separate publicly held companies.

Basis of Presentation

The consolidated statements of operations include all revenues and costs directly attributable to us, including costs for facilities and costs for functions and services performed by CenterPoint and directly charged to us based on usage or other allocation factors prior to the Distribution. The results of operations in these consolidated financial statements also include general corporate expenses allocated by CenterPoint to us prior to the Distribution. All of the allocations in the consolidated financial statements are based on assumptions that management believes are reasonable under the circumstances. However, these allocations may not necessarily be indicative of the costs and expenses that would have resulted if we had operated as a separate entity prior to the Distribution.

(2) Summary of Significant Accounting Policies

(a) Reclassifications.

Some amounts from the previous years have been reclassified to conform to the 2003 presentation of financial statements. These reclassifications do not affect earnings.

(b) Use of Estimates and Market Risk and Uncertainties.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Our critical accounting estimates include: (a) goodwill, (b) California net receivables, (c) property, plant and equipment, (d) depreciation expense, (e) trading and derivative activities, (f) retail energy segment estimated revenues and energy supply costs, (g) contingencies and (h) deferred tax assets valuation allowance and tax liabilities.

We are subject to the risk associated with price movements of energy commodities and the credit risk associated with our commercial activities. For additional information regarding these risks, see notes 2(d) and 7. We are subject to risks relating to the reliability of the systems, procedures and other infrastructure necessary to operate our business. We are also subject to risks relating to changes in laws and regulations; the outcome of pending lawsuits, governmental proceedings and investigations; the effects of competition; liquidity concerns in our markets; changes in interest rates; the availability of adequate supplies of fuel and transportation; weather conditions; financial market conditions and our access to capital; the creditworthiness or financial distress of our counterparties; actions by rating agencies with respect to us or our competitors; political, legal, regulatory and economic conditions and developments; the successful operation of deregulating power markets and other items.

(c) Principles of Consolidation.

Our accounts and those of our wholly-owned and majority-owned subsidiaries are included in the consolidated financial statements. All significant intercompany transactions and balances are eliminated in consolidation.

We do not, or did not until the indicated date, consolidate the following interests:

- a receivables facility arrangement, which involves a qualified special purpose entity (QSPE) formed as a bankruptcy remote subsidiary in 2002, that we entered into with financial institutions that purchase undivided interests in our accounts receivable from certain retail customers (see note 16);
- sale-leaseback transactions involving three power generating facilities entered into in 2000 (see note 14(a));
- two equity investments (see below and note 8); and
- until January 1, 2003, arrangement to facilitate the development, financing, construction and leasing of three power generation projects beginning in 2001 (see below and notes 9(a) and 14(b)).

We use the equity method of accounting for investments in entities in which we have an ownership interest between 20% and 50% and exercise significant influence primarily through representation on management committees. For our equity method accounting investments, our representation on management committees does not enable us to control the investments' management and operating decisions. The allocation of profits and losses is based on our ownership interest. For additional information regarding investments recorded using the equity method of accounting, see note 8. Other investments, excluding marketable securities, are carried at cost. For these other investments, we do not exercise significant influence. For additional information regarding these investments, see note 2(o).

In January 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51," (FIN No. 46). The objective of FIN No. 46 is to achieve more consistent application of consolidation policies to variable

interest entities and to improve comparability between enterprises engaged in similar activities. FIN No. 46 states that an enterprise must consolidate a variable interest entity if the enterprise has a variable interest that will absorb a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both. FIN No. 46 requires entities to either (a) record the effects prospectively with a cumulative effect adjustment as of the date on which FIN No. 46 is first applied or (b) restate previously issued financial statements for the years with a cumulative effect adjustment as of the beginning of the first year being restated.

We adopted FIN No. 46 on January 1, 2003, as it relates to our variable interests in three power generation projects that were being constructed by off-balance sheet entities under construction agency agreements, which pursuant to this guidance required consolidation upon adoption. Results for 2003 include the cumulative effect of accounting change of $1 million loss, net of tax. As of January 1, 2003, these entities had property, plant and equipment of $1.3 billion, net other assets of $3 million and secured debt obligations of $1.3 billion. These entities' financing agreements, the construction agency agreements and the related guarantees were terminated as part of the refinancing in March 2003. For information regarding the refinancing, see note 9(a).

In December 2003, the FASB released FASB Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51" (FIN No. 46R), which replaces FIN No. 46 and modified certain criteria in determining which entities should be considered as variable interest entities. We do not believe the application of FIN No. 46R will have a material impact to our consolidated financial statements. The application of FIN No. 46R continues to evolve as the FASB continues to address issues submitted for consideration. We will continue to assess our application of clarified or revised guidance related to FIN No. 46R.

(d) Revenues and Accounting for Hedging and Trading Activities.

Power Generation Revenues. We record gross revenues for energy sales and services related to our electric power generation facilities under the accrual method and these revenues generally are recognized upon delivery. Electric power and other energy services are sold at market-based prices through existing power exchanges or through third-party contracts. Energy sales and services related to our electric power generation facilities not billed by month-end are accrued based upon estimated energy and services delivered. See below for the discussion of the impact of implementation of Emerging Issues Task Force (EITF) Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" As Defined in EITF Issue No. 02-03" (EITF No. 03-11).

Retail Energy Revenues. We record gross revenues for energy sales and services to residential, small commercial and large commercial, industrial and institutional retail electric customers that have not executed a contract under the accrual method and these revenues generally are recognized upon delivery. Our electricity sales to large commercial, industrial and institutional customers under contracts executed after October 25, 2002 are typically accounted for under the accrual method and these gross revenues are generally recognized upon delivery.

Our electricity sales to large commercial, industrial and institutional customers under contracts executed before October 25, 2002 were accounted for under the mark-to-market method of accounting upon contract execution. See further discussion below of the impact of implementation of EITF Issue No. 02-03, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," (EITF No. 02-03) rescinding EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," (EITF No. 98-10).

The determination of retail energy sales is based on the reading of customer meters by the transmission and distribution utilities. The transmission and distribution utilities in Texas send the information to the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ERCOT ISO), which in turn sends the information to us. We may be limited in our ability to confirm the accuracy of such information. This activity occurs 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. Unbilled revenue is estimated each month based on estimated volumes for each customer class and derived from weather factors and analyses of historical trends and experience. As of December 31, 2002 and 2003, our retail energy segment had accrued unbilled revenues of $216 million and $290 million, respectively. As additional information becomes available, we revise our estimated revenues related to prior periods and record the results in subsequent periods. We believe that the estimates and assumptions utilized to recognize revenues are reasonable and represent our best estimates. However, actual results can differ from those estimates.

Hedging Activities. Effective January 1, 2001, we adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133), which establishes accounting and reporting standards for derivative instruments. Adoption of SFAS No. 133 on January 1, 2001 resulted in an after-tax increase in net income of $3 million and a cumulative after-tax increase in accumulated other comprehensive loss of $439 million. During 2001, $230 million of the initial after-tax transition adjustment recorded in accumulated other comprehensive loss was recognized in net income.

If certain conditions are met, we may designate a derivative instrument as hedging (a) the exposure to variability in expected future cash flows (cash flow hedge), (b) the exposure to changes in the fair value of an asset or liability (fair value hedge) or (c) the foreign currency exposure of a net investment in a foreign operation. This statement requires that a derivative be recognized at fair value in the balance sheet whether or not it is designated as a hedge. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are designated as normal purchases and sales exceptions and are not reflected in our consolidated balance sheets at fair value. For a derivative that is designated as a cash flow hedge, and depending on its effectiveness, changes in fair value are deferred as a component of accumulated other comprehensive income (loss), net of applicable taxes.

We designate our derivatives utilized in non-trading activities as cash flow hedges only if there is a high correlation between price movements in the derivative and the item designated as being hedged. This correlation is measured both at the inception of the hedge and on an ongoing basis, with an acceptable level of correlation of at least 80% to 125% for hedge designation. The gains and losses related to derivative instruments designated as cash flow hedges are deferred in accumulated other comprehensive income (loss), net of tax, to the extent the contracts are effective as hedges, and then are recognized in our results of operations in the same period as the settlement of the underlying hedged transactions. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive income (loss) is reclassified and included in our consolidated statements of operations (a) prior to October 1, 2003, under the captions (i) fuel expenses, in the case of hedging activities related to physical natural gas purchases, (ii) purchased power, in the case of hedging activities related to physical power purchases, (iii) revenues, in the case of hedging activities related to physical power and natural gas sales transactions and financial transactions and (iv) interest expense, in the case of interest rate hedging activities and (b) effective October 1, 2003, under the captions (i) fuel expenses, in case of hedging activities related to physical natural gas purchases and physical natural gas sales transactions that do not physically flow, (ii) purchased power, in the case of hedging activities related to physical power purchases that do physically flow, (iii) revenues, in the case of hedging activities related to financial transactions, physical power sales transactions, physical power purchases that do not physically flow and natural gas

sales transactions that do physically flow and (iv) interest expense, in the case of interest rate hedging activities.

For a derivative not designated as a hedge, changes in fair value are recorded as unrealized gains or losses in our results of operations. The impact of our derivative instruments hedging foreign currency exposures are reported in discontinued operations in our consolidated financial statements. If and when correlation ceases to exist at an acceptable level, hedge accounting ceases and changes in fair value are recognized currently in our results of operations. If it becomes probable that a forecasted transaction will not occur, we immediately recognize the respective deferred gains or losses in our results of operations. The associated hedging instrument is then marked to market through our results of operations for the remainder of the contract term unless a new hedging relationship is redesignated. Prior to October 1, 2003, revenues, fuel and cost of gas sold, and purchased power related to sale and purchase contracts designated as hedges were generally recorded on a gross basis in the delivery period. In July 2003, the EITF issued EITF No. 03-11, which stated that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. On October 1, 2003, we began reporting prospectively the settlement of sales and purchases of fuel and purchased power related to our non-trading commodity derivative activities that were not physically delivered on a net basis in our consolidated statement of operations based on the item hedged. This change resulted in decreased revenues and a corresponding decrease in fuel and cost of gas sold and purchased power of $834 million for the fourth quarter of 2003. We believe the application of EITF No. 03-11 will continue to result in a significant amount of our non-trading commodity derivative activities being reported on a net basis prospectively that were previously reported on a gross basis. EITF No. 03-11 has no impact on margins or net income. Comparative financial statements for prior periods have not been reclassified to conform to this presentation, as it is not required. In addition, it is not practicable for us to determine sales and purchases of fuel and purchased power in 2001, 2002 and the nine months ended September 30, 2003 that would have been shown net if EITF No. 03-11 had been applied to our results of operations historically.

In April 2003, the FASB issued SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 149 clarifies when a contract with an initial net investment meets the characteristics of a derivative and when a derivative contains a financing component. SFAS No. 149 also amends certain existing pronouncements, which will result in more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003 and should be applied prospectively. The implementation of SFAS No. 149 did not have a material impact on our consolidated financial statements.

For additional discussion of derivative and hedging activities, see note 7.

Trading Activities. In March 2003, we discontinued our proprietary trading business. Trading positions taken prior to our decision to exit this business are managed solely for purposes of closing them on economical terms. See note 7(b) for discussion of the types of activities that were classified as trading activities in our historical results of operations.

In 2002, the EITF reached a consensus that all mark-to-market gains and losses on energy trading contracts should be shown net in the statement of operations whether or not settled physically. Beginning in the quarter ended September 30, 2002, we report all energy trading activities on a net basis in the consolidated statements of operations. Comparative financial statements for prior periods were reclassified to conform to this presentation.

Furthermore, in 2002, the EITF reached a consensus to rescind EITF No. 98-10. All contracts that would have been accounted for under EITF No. 98-10, and that do not fall within the scope of

SFAS No. 133, may no longer be marked-to-market through earnings, effective October 25, 2002. In addition, mark-to-market accounting is no longer applied to inventories used in our trading activities. This transition was effective for us (a) on January 1, 2003 for contracts executed prior to October 25, 2002 and (b) on October 25, 2002 for contracts executed on or after that date. We recorded a cumulative effect of a change in accounting principle of $42 million loss, net of tax of $22 million, or $0.14 per share, effective January 1, 2003, related to EITF No. 02-03. The cumulative effect reflects the fair value, as of January 1, 2003, of contracts executed prior to October 25, 2002 that had been marked to market under EITF No. 98-10 that did not meet the definition of a derivative under SFAS No. 133.

Our historical legacy energy trading activities and certain power origination activities are accounted for under the mark-to-market method of accounting. Under the mark-to-market method of accounting, net changes in the fair value of derivative instruments are recognized in our consolidated statements of operations as revenues in the period of change. The recognized, unrealized balances are recorded at fair value in trading and derivative assets/liabilities in the consolidated balance sheets. Trading revenues related to the sale of natural gas, electric power and other energy related commodities are recorded on a net basis, as discussed above.

Prior to 2003, our electricity sales to large commercial, industrial and institutional customers under executed contracts (and the related energy supply contracts) for contracts executed prior to October 25, 2002 were accounted for under the mark-to-market method of accounting pursuant to EITF No. 98-10. Accordingly, these contractual commitments were recorded at fair value in revenues on a net basis upon contract execution. As of December 31, 2002, the recognized, unrealized balances were recorded at fair value in trading and derivative assets/liabilities in the consolidated balance sheet. Beginning in January 2003, we began applying the normal purchase and sale exception of SFAS No. 133 to a substantial portion of our retail large commercial, industrial and institutional sales contracts and the related energy supply agreements and began utilizing accrual accounting. The related revenues and energy supply costs are recorded on a gross basis in our results of operations. The results of operations related to our electricity sales to large commercial, industrial and institutional customers for contracts executed prior to October 25, 2002 are not comparable between 2001, 2002 and 2003 because of this change. During 2001 and 2002, we recognized $73 million and $(6) million, respectively, of unrealized net gains (losses) related to our electricity sales to large commercial, industrial and institutional customers and the related energy supply contracts. During 2003, volumes were delivered under electricity sales to large commercial, industrial and institutional customers under executed contracts and the related energy supply contracts for which $66 million was previously recognized as unrealized earnings. As of December 31, 2003, we have unrealized gains that have been previously recorded in our results of operations of $27 million that will be realized upon delivery of the electricity ($21 million in 2004 and $6 million in 2005). These unrealized gains are recorded in trading and derivative assets/liabilities in our consolidated balance sheet as of December 31, 2003 and the related contracts are accounted for as cash flow hedges or normal purchases and sales contracts under SFAS No. 133.

During 2001 and 2002, we recorded $119 million and $57 million, respectively, of fair value at the contract inception related to trading activities, including our electricity sales to large commercial, industrial and institutional customers and the related energy supply contracts. Inception gains recorded were evidenced by quoted market prices and other current market transactions for energy trading contracts with similar terms and counterparties.

For additional discussion regarding trading revenue recognition and the related estimates and assumptions that can affect reported amounts of such revenues, see note 7.

Classification of Economic Hedges. Effective January 1, 2003, we changed our classification of certain derivative activities that historically were classified as trading activities to non-trading activities. These transactions do not meet the requirements for hedge accounting treatment under SFAS No. 133;

however, such transactions were entered into to economically hedge commodity risk associated with our wholesale energy power generation operations. As of January 1, 2003, the amounts of non-trading derivative assets and liabilities previously classified as trading assets and liabilities were $52 million and $44 million, respectively. Corresponding amounts for these activities have not been reclassified for periods prior to January 1, 2003 as prior period amounts were not material to our consolidated financial statements.

Set-off of Trading and Derivative Assets and Liabilities. Where trading and derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts," are met, we present our trading and derivative assets and liabilities on a net basis in our consolidated balance sheets. Trading and derivative assets/liabilities and accounts receivable/payable are presented separately in our consolidated balance sheets. The trading and derivative assets/liabilities and accounts receivable/payable are set-off separately in our consolidated balance sheets although in certain cases contracts permit the set-off of trading and derivative assets/liabilities and accounts receivable/payable with a given counterparty.

(e) General, Administrative and Development Expenses.

The general and administrative expenses in the consolidated statements of operations include (a) employee-related costs of the trading and risk management services activities, (b) certain contractor costs, (c) advertising, (d) bad debt expense, (e) marketing and market research, (f) corporate and administrative services (including management services, financial and accounting, cash management and treasury support, legal, information technology system support, office management and human resources) and (g) certain benefit costs. Some of these expenses were allocated from CenterPoint prior to the Distribution as further discussed in notes 1 and 3.

(f) Property, Plant and Equipment and Depreciation Expense.

We record property, plant and equipment at historical cost. We recognize repair and maintenance costs incurred in connection with planned major maintenance, such as turbine and generator overhauls, under the "accrue-in-advance" method for our power generation operations acquired or developed prior to December 31, 1999. Planned major maintenance cycles primarily range from two to 12 years. Under the accrue-in-advance method, we estimate the costs of planned major maintenance and accrue the related expense over the maintenance cycle. As of December 31, 2002 and 2003, our major maintenance reserve was $7 million and $10 million, respectively, of which $1 million and $0, respectively, were included in other current liabilities. We expense all other repair and maintenance costs as incurred. For power generation operations acquired or developed subsequent to January 1, 2000, we expense all repair and maintenance costs as incurred, including planned major maintenance. Depreciation is computed using

the straight-line method based on estimated useful lives. Property, plant and equipment includes the following:

	Estimated Useful Lives (Years)	December 31, 2002	December 31, 2003
		(In millions)	
Electric generation facilities	10 – 50	$5,676	$6,760
Building and building improvements	5 – 30	20	42
Land improvements	15 – 50	481	513
Other	3 – 10	381	430
Land		203	205
Assets under construction		652	1,301
Total		7,413	9,251
Accumulated depreciation		(422)	(724)
Property, plant and equipment, net		$6,991	$8,527

We periodically evaluate property, plant and equipment for impairment when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. A resulting impairment loss is highly dependent on the underlying assumptions. During 2001, we determined equipment associated with our communications business was impaired and accordingly recognized $22 million of equipment impairments (see note 17). During 2002, we determined that steam and combustion turbines and two heat recovery steam generators purchased in September 2002 were impaired and accordingly recognized a $37 million impairment loss (see note 14(c)). During 2002, we also recognized $15 million in depreciation expense for the early retirement of power generation units at the Warren facility. During 2003, we recorded the following in depreciation expense: $14 million for the early retirement of certain power generation units and $7 million related to the write-down of an office building to its fair value less costs to sell. As of December 31, 2002 and 2003, we performed impairment analyses of certain of our wholesale energy segment's property, plant and equipment. In addition, in November 2002 and July 2003, we performed impairment analyses of all of our wholesale energy segment's property, plant and equipment as we believed events had indicated that these assets may not be recoverable. Based on these analyses, we recorded no impairments.

Over the past few years, margins on the sales of electricity in our industry have decreased substantially. If our wholesale energy market outlook changes negatively, we could have impairments of property, plant and equipment in future periods. In addition, our ongoing evaluation of our wholesale energy business could result in decisions to mothball, retire or dispose of additional generation assets, any of which could result in additional impairment charges.

See note 15(c) for discussion of our Liberty Electric PA, LLC (Liberty) generating station.

(g) Goodwill and Amortization Expense.

We record goodwill for the excess of the purchase price over the fair value assigned to the net assets of an acquisition. Through 2001, we amortized goodwill on a straight-line basis over 15 to 40 years. Pursuant to our adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) on January 1, 2002, we discontinued amortizing goodwill. See note 6 for a discussion regarding our adoption of SFAS No. 142. Goodwill amortization expense was $25 million for 2001, including a $19 million impairment related to the communications business (see note 17). Amortization expense for other

intangibles, excluding contractual rights and obligations, was $44 million, $51 million and $59 million for 2001, 2002 and 2003, respectively. See also note 6.

We periodically evaluate goodwill and other intangibles when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. In 2001, the determination of whether an impairment had occurred was based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. During 2001, we determined goodwill associated with our communications business was impaired and accordingly recognized $19 million of goodwill impairments. Effective January 1, 2002, goodwill and other intangibles are evaluated for impairment in accordance with SFAS No. 142 (see note 6). In 2002, we recognized an impairment charge of $234 million (pre-tax and after-tax) relating to our European energy segment goodwill in connection with the adoption of SFAS No. 142. Due to the disposition of our Desert Basin plant operations, we tested our wholesale energy segment's goodwill for impairment effective July 2003. In connection with this analysis, we recognized an impairment of $985 million (pre-tax and after-tax) relating to our wholesale energy reporting unit. For further discussion of goodwill and other intangible asset impairment analyses in 2002 and 2003, see note 6.

(h) Stock-based Compensation Plans.

We apply the intrinsic value method of accounting for employee stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25). Under the intrinsic value method, no compensation expense is recorded when options are issued with an exercise price equal to or greater than the market price of the underlying stock on the date of grant. Since our stock options to employees have all been granted with the exercise price equal to market value at date of grant, no compensation expense has been recognized under APB No. 25. We comply with the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) and SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment to SFAS No. 123" (SFAS No. 148) and disclose the pro forma effect on net income (loss) and per share amounts as if the fair value method of accounting had been applied to all stock awards. The FASB has announced that it plans to require all companies to expense the fair value of employee stock options in 2005. The FASB is still evaluating "fair value" valuation models and other items.

If compensation costs had been determined as prescribed by SFAS No. 123, our net income (loss) and per share amounts would have approximated the following pro forma results for 2001, 2002 and 2003, which take into account the amortization of stock-based compensation, including performance shares,

purchases under the employee stock purchase plan and stock options, to expense on a straight-line basis over the vesting periods:

	Year Ended December 31,		
	2001	2002	2003
	(In millions, except per share amounts)		
Net income (loss), as reported	$ 563	$ (560)	$(1,342)
Add: Stock-based employee compensation expense included in reported net income/loss, net of related tax effects	5	2	7
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(34)	(38)	(42)
Pro forma net income (loss)	$ 534	$ (596)	$(1,377)
Earnings (loss) per share:			
Basic, as reported	$2.03	$(1.93)	$ (4.57)
Basic, pro forma	$1.93	$(2.05)	$ (4.69)
Diluted, as reported	$2.03	$(1.92)	$ (4.57)
Diluted, pro forma	$1.93	$(2.04)	$ (4.69)

For further information regarding our stock-based compensation plans, see note 12(a).

(i) Capitalization of Interest Expense.

Interest expense is capitalized as a component of major projects under construction and is amortized over the estimated useful lives of the assets. During 2001, 2002 and 2003, we capitalized interest of $59 million, $27 million and $84 million, respectively.

(j) Income Taxes.

We use the asset and liability method of accounting for deferred income taxes and measure deferred income taxes for all significant income tax temporary differences. For additional information regarding income taxes, see note 13.

Prior to October 1, 2002, we were included in the consolidated federal income tax returns of CenterPoint and we calculated our income tax provision on a separate return basis under a tax sharing agreement with CenterPoint. Pursuant to agreements with CenterPoint, we were owed amounts related to certain loss carryovers, income inclusions from foreign affiliates, net income tax receivables/payables relating to our operations prior to the Distribution and other tax liabilities. Prior to October 1, 2002, current federal and some state income taxes were payable to or receivable from CenterPoint. Subsequent to the Distribution, we file a separate federal tax return. See note 13 for further discussion.

(k) Cash.

We record as cash and cash equivalents all highly liquid short-term investments with original maturities or remaining maturities at date of purchase of three months or less.

(l) Restricted Cash.

Restricted cash primarily includes cash at certain subsidiaries, the distribution or transfer of which to Reliant Resources or our other subsidiaries, is restricted by financing and other agreements, but is available to the applicable subsidiary to use to satisfy certain of its obligations. For a discussion of our various financing agreements, see note 9. The following table details our current and long-term restricted cash by reporting segment and entity:

	December 31,	
	2002	2003
	(In millions)	
Other Operations Segment:		
Reliant Resources	$ 7(1)	$ 7(1)
Wholesale Energy Segment:		
Orion Power Holdings, Inc.	—	23(2)
Orion Power MidWest, L.P.	72(2)	64(2)
Orion Power New York, L.P.	73(2)	119(2)
Orion Power Capital, LLC	27(2)	—(2)
Liberty Electric PA, LLC	28(2)	15(2)
Reliant Energy Mid-Atlantic Power Holdings, LLC	—	42(3)
Reliant Energy Channelview, L.P.	13(4)	18(4)
Total current and long-term restricted cash	$220	$288

(1) This restricted cash is pledged to secure the payment and performance related to the issuance of certain surety bonds.

(2) The credit facilities and other debt agreements of Orion Power Holdings, Inc. and certain of its subsidiaries contain various covenants that include, among others, restrictions on the payment of dividends to Orion Power Holdings, Inc. and/or us unless certain conditions are satisfied.

(3) See notes 9(a) and 14(a).

(4) The credit agreement of our subsidiary that owns an electric power generation facility in Channelview, Texas, contains restrictive covenants that restrict Reliant Energy Channelview, L.P.'s (Channelview) ability to, among other things, make dividend distributions unless Channelview satisfies various conditions.

(m) Allowance for Doubtful Accounts.

Accounts and notes receivable, principally from customers, in the consolidated balance sheets are net of an allowance for doubtful accounts of $68 million and $74 million at December 31, 2002 and 2003, respectively. The net provision for doubtful accounts in the consolidated statements of operations for 2001, 2002 and 2003 was $38 million, $21 million and $79 million, respectively. These amounts include items written off during the years related to refunds for energy sales in California (see note 15(b)) and related to Enron Corp. and its affiliates (Enron) (see note 15(a)). We accrue a provision for doubtful accounts based upon estimated percentages of uncollectible power generation and retail energy revenues. We determine these percentages from counterparty credit ratings, historical collections, accounts receivable aging analyses and other factors. We review the provision and estimated percentages periodically and adjust them as appropriate. We write-off accounts receivable balances against the allowance for doubtful accounts when we deem the receivable to be uncollectible.

(n) Inventory.

Inventory consists of materials and supplies, including spare parts, coal, natural gas and heating oil. Inventories used in the production of electricity are valued at the lower of average cost or market. Heating

oil and natural gas used in the trading activities were accounted for under mark-to-market accounting through 2002, as discussed in note 2(d). Beginning January 1, 2003, this inventory is no longer marked to market in accordance with EITF No. 02-03 and is now valued at the lower of average cost or market. Below is a detail of inventory:

	December 31,	
	2002	2003
	(In millions)	
Materials and supplies	$112	$142
Coal	42	34
Natural gas	78	42
Heating oil	43	51
Total inventory	$275	$269

(o) Investments.

As of December 31, 2002 and 2003, we have other non-marketable investments of $39 million and $32 million, respectively, in which we have ownership interests of less than 20% and do not exercise significant influence, which are carried at cost and are included in other long-term assets in our consolidated balance sheets. During 2002, we incurred a pre-tax impairment loss of $32 million ($30 million after-tax) related to certain of these investments in connection with reduced cash flow expectations for these investments, management's decision to minimize further financial support and management's intent to sell certain investments in the near-term below our cost basis.

(p) Environmental Costs.

We expense or capitalize environmental expenditures, as appropriate, depending on their future economic benefit. We expense amounts that relate to an existing condition caused by past operations and that do not have future economic benefit. We record liabilities related to expected future costs related to environmental assessments and/or remediation activities when they are probable and the costs can be reasonably estimated. See note 15(a) for further discussion.

(q) Asset Retirement Obligations.

On January 1, 2003, we adopted 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. Prior to the adoption of SFAS No. 143, we recorded asset retirement obligations in connection with certain business combinations. These obligations were recorded at their present values on the dates of acquisition. Our asset retirement obligations primarily related to the required future dismantling of power plants and auxiliary equipment at our European energy operations, which have subsequently been sold and future dismantlement of power plants on leased property and environmental obligations related to ash disposal site closures.

The impact of the adoption of SFAS No. 143 resulted in a gain of $19 million, net of tax of $10 million, or $0.06 per share, as a cumulative effect of an accounting change in our consolidated statement of operations for 2003. Included in the gain is $16 million, net of tax of $7 million, related to our European energy operations, which are now reported as discontinued operations and have subsequently been sold. The impact of the adoption of SFAS No. 143 for our continuing operations resulted in a

January 1, 2003 cumulative effect of an accounting change to record (a) a $6 million increase in the carrying values of property, plant and equipment, (b) a $1 million increase in accumulated depreciation of property, plant and equipment, (c) a $1 million decrease in asset retirement obligations and (d) a $3 million increase in deferred income tax liabilities.

If we had adopted SFAS No. 143 on January 1, 2001, the impact would have been immaterial to our consolidated income from continuing operations and net income (loss) for both 2001 and 2002.

The following table presents the detail of our asset retirement obligations for continuing operations, which are included in other long-term liabilities in our consolidated balance sheet (in millions):

Balance at January 1, 2003	$11
Accretion expense	1
Payments	(4)
Balance at December 31, 2003	$ 8

(r) Deferred Financing Costs.

Deferred financing costs are costs incurred in connection with obtaining financings. These costs are deferred and amortized, using the effective interest method, over the life of the related debt. From October 1, 2002 through December 31, 2003, we had incurred approximately $243 million in financing costs (which includes the net present value of $15 million to be paid in March 2007) related to our 2003 refinancing and June and July 2003 debt issuances. We capitalized $207 million and directly expensed $36 million (of which $12 million was expensed in the fourth quarter of 2002 and $24 million was expensed in the first quarter of 2003, respectively) in fees and other costs related to these financings. During 2001, 2002 and 2003, we amortized $1 million, $3 million and $105 million of deferred financing costs to interest expense. Included in our results for 2003 was the write-off of $55 million of previously deferred financing costs related to the March 2003 refinancing in connection with the prepayment of senior secured term loans and the cancellation of our senior priority facility in 2003. As of December 31, 2002 and 2003, we had $68 million and $192 million, respectively, of net deferred financing costs classified in other long-term assets in our consolidated balance sheets. See note 9 for discussion of our various financing agreements.

(s) Foreign Currency Adjustments.

Local currencies are the functional currency of our foreign operations. Foreign subsidiaries' assets and liabilities have been translated into U.S. dollars using the exchange rate at the balance sheet date. Revenues, expenses, gains and losses have been translated using the weighted average exchange rate for each month prevailing during the periods reported. Cumulative adjustments resulting from translation have been recorded as a component of accumulated other comprehensive loss in stockholders' equity.

(t) Guarantees and Indemnifications.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Direct Guarantees of Indebtedness of Others," (FIN No. 45) which increases the disclosure requirements for a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also requires a guarantor to recognize, at the inception of a guarantee issued after December 31, 2002, a liability for the fair value of the obligation undertaken in issuing the guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. We adopted the reporting requirements of FIN No. 45 on January 1, 2003. The adoption of FIN No. 45

had no impact to our historical financial statements, as existing guarantees are not subject to the measurement provisions. The adoption of FIN No. 45 did not have a material impact on our consolidated financial position or results of operations as of and for the year ended December 31, 2003 as the fair value of guarantees issued after December 31, 2002 was nominal on the date on which the guarantee was issued. See note 14(e).

(u) Disclosures About Pensions and Other Postretirement Benefits.

In December 2003, the FASB issued a revision to SFAS No. 132, "Employers' Disclosures About Pensions and Other Postretirement Benefits — An Amendment of FASB Statements No. 87, 88 and 106" (SFAS No. 132 (Revised 2003)). This statement revises employers' disclosures about pension plans and other postretirement benefit plans. This statement retains the disclosure requirements contained in SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132), which it replaces. It requires additional disclosures to those in the original SFAS No. 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. We have adopted these additional disclosures. See note 12(b).

(v) New Accounting Pronouncements.

As of February 20, 2004, no standard setting body or authoritative body has established new accounting pronouncements or changes to existing accounting pronouncements that would have a material impact to our results of operations, financial position or cash flows, for which we have not already adopted and/or disclosed elsewhere in these notes.

(3) Historical Related Party Transactions

Prior to the Distribution, CenterPoint was a related party. Transactions with CenterPoint subsequent to the Distribution are not reported as affiliated transactions. We had, or continue to have (as indicated) the following agreements/transactions with CenterPoint:

Indemnities and Releases. We have agreements with CenterPoint providing for mutual indemnities and releases with respect to our respective businesses and operations, corporate governance matters, the responsibility for employee compensation and benefits, and the allocation of tax liabilities. The agreements also require us to indemnify CenterPoint for any untrue statement of a material fact, or omission of a material fact necessary to make any statement not misleading, in the registration statement or prospectus that we filed with the Securities and Exchange Commission (SEC) in connection with our IPO. We have also guaranteed, in the event CenterPoint becomes insolvent, certain non-qualified benefits of CenterPoint's and its subsidiaries' existing retirees at the date of Distribution totaling approximately $57 million as of December 31, 2003.

Corporate Support Services. CenterPoint agreed to provide us various corporate support services, information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics services. Certain of these arrangements will continue until December 31, 2004; however, we have the right to terminate categories of services at an earlier date. The charges we pay to CenterPoint for these services allow CenterPoint to recover its fully allocated costs, plus out-of-pocket costs and expenses. The costs of services have been directly charged or allocated to us using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment, and proportionate corporate formulas based on assets, operating expenses and employees. These charges and allocations are not necessarily indicative of what would have been incurred had we been an unaffiliated entity. Amounts charged and allocated to us for these services for 2001 and the nine months ended September 30, 2002,

were $9 million and $15 million, respectively, and are included primarily in operation and maintenance expenses and general and administrative expenses. Net interest income related to various net receivables representing transactions between us and CenterPoint was $12 million and $5 million during 2001 and the nine months ended September 30, 2002, respectively.

Leases. We leased office space in CenterPoint's corporate headquarters and continue to lease office space in various CenterPoint facilities in Houston, Texas, including a data center. Our lease at CenterPoint's corporate headquarters expired in January 2004, except with respect to an insignificant amount of space used primarily for information technology operations. We also have various agreements with CenterPoint relating to ongoing commercial arrangements, including the leasing of optical fiber and related maintenance activities, gas purchasing and agency matters and subcontracting energy services under existing contracts. During 2001 and the nine months ended September 30, 2002, we incurred $16 million and $24 million, respectively, of rent expense to CenterPoint.

Purchases and Sales of Energy Commodities, Transportation and Related Services. In 2002, we purchased natural gas, natural gas transportation services, electric generation energy and capacity, and electric transmission services from, supplied natural gas to, and provided marketing and risk management services to CenterPoint. Purchases of electric generation energy and capacity and electric transmission services from CenterPoint were $1.5 billion for the nine months ended September 30, 2002. During 2001 and the nine months ended September 30, 2002, the net purchases and sales and services from/to CenterPoint and its subsidiaries related to our trading operations totaled $469 million and $161 million, respectively. In addition, during 2001 and the nine months ended September 30, 2002, other sales and services to CenterPoint and its subsidiaries totaled $56 million and $15 million, respectively.

Equity Contributions. During 2001, 2002 and 2003, CenterPoint made equity contributions to us of $1.8 billion, $53 million and $45 million, respectively. The contributions in 2001 primarily related to the conversion into equity of debt owed to CenterPoint and some related interest expense totaling $1.7 billion and the contribution of net benefit assets and liabilities, net of deferred income taxes. The contributions in 2002 primarily related to benefit obligations, net of deferred income taxes. The contributions in 2003 primarily related to the non-cash conversion to equity of accounts payable to CenterPoint.

Services Provided to CenterPoint. Through 2001, we provided billing, customer service, credit and collection and remittance services to certain of CenterPoint's regulated utilities. The charges CenterPoint paid us for these services allowed us to recover our fully allocated costs of providing the services, plus out-of-pocket costs and expenses.

(4) Agreements Relating to Texas Genco

Texas Genco, LP is a wholly-owned subsidiary of Texas Genco Holdings, Inc., a majority-owned subsidiary of CenterPoint, and owns the Texas generating assets formerly held by CenterPoint's electric utility division. Texas Genco, LP and Texas Genco Holdings, Inc. are collectively referred to herein as "Texas Genco."

In January 2003, CenterPoint distributed approximately 19% of the common stock of Texas Genco to CenterPoint shareholders. CenterPoint granted us an option to purchase all of the remaining shares of common stock of Texas Genco held by CenterPoint. The option expired unexercised on January 24, 2004.

Texas Genco, as the affiliated power generator of CenterPoint's electric utility, is required by law to sell at auction 15% of the output of its installed generating capacity. These auction obligations will continue until January 2007, unless at least 40% of the electricity consumed by residential and small commercial customers in CenterPoint's service territory is being provided by retail electric providers other than us. We are not currently able to participate in these legally mandated capacity auctions. Under CenterPoint's prior agreement with us, Texas Genco was required to auction the remainder of its capacity

after certain other adjustments, and we had the right to participate directly in such auctions. Texas Genco's obligation to auction its remaining capacity and our associated rights terminated when we decided not to exercise our option to acquire CenterPoint's ownership interest in Texas Genco.

We have a master power purchase contract with Texas Genco covering, among other things, our purchases of capacity and/or energy from Texas Genco's generating units. In connection with this contract, we have granted Texas Genco a security interest in our rights in the accounts receivable and related assets of certain of our subsidiaries. The liens on our rights in the accounts receivables and related assets are junior to our receivables facility and senior to our March 2003 credit facilities and to our senior secured notes. See note 16. The term of the master power purchase contract terminates on January 24, 2005.

We have purchased entitlements to some of the generation capacity of electric generation assets of Texas Genco. We purchased these entitlements in capacity auctions conducted by Texas Genco. As of December 31, 2003, we had purchased entitlements to capacity of Texas Genco averaging 6,376 megawatts (MW) per month in 2004 and 923 MW per month in 2005. Our anticipated capacity payments related to these capacity entitlements are $714 million. The capacity entitlements are accounted for as normal purchases under SFAS No. 133. See notes 2(d) and 7 for discussion of our derivative financial instruments.

Under a support agreement with CenterPoint, we provide engineering and technical support services and environmental, safety and industrial health services to support operations and maintenance of Texas Genco's facilities. We also provide systems, technical, programming and consulting support services and hardware maintenance (but excluding plant-specific hardware) necessary to provide dispatch planning, dispatch, settlement and communication with the independent system operator. The fees we charge for these services are designed to allow us to recover our fully allocated direct and indirect costs and reimbursement of out-of-pocket expenses. Expenses associated with capital investment in systems and software that benefit both the operation of Texas Genco's facilities and our facilities in other regions are allocated on an installed MW basis. The term of this agreement will end on the first occur of (a) CenterPoint's sale of Texas Genco, or all or substantially all of the generating assets of Texas Genco or (b) May 31, 2005; however, Texas Genco may extend the term of this agreement until December 31, 2005. In addition, Texas Genco has the right to terminate all or a portion of the services provided under the agreement upon 90 days' notice. In February 2004, Texas Genco notified us that it will terminate the technical support services and the environmental, safety and industrial health services provided under the support agreement. The effective date of termination is May 2004.

(5) Business Acquisition

In February 2002, we acquired all of the outstanding shares of common stock of Orion Power Holdings, Inc. (Orion Power Holdings) for an aggregate purchase price of $2.9 billion and assumed debt obligations of $2.4 billion. Orion Power refers to Orion Power Holdings, Inc. and its subsidiaries, unless we specify or the context indicates otherwise. We primarily funded the acquisition with a $2.9 billion credit facility. Orion Power is an electric power generating company with generating assets in the states of New York, Pennsylvania, Ohio and West Virginia.

As of February 19, 2002, Orion Power had 81 generating facilities with a total generating capacity of 5,644 MW and two development projects with an additional 804 MW of capacity under construction. Both projects under construction had reached commercial operation by December 31, 2002.

We accounted for the acquisition as a purchase with assets and liabilities of Orion Power reflected at their estimated fair values. Our fair value adjustments primarily included adjustments in property, plant and equipment, contracts, severance liabilities, debt, unrecognized pension and postretirement benefits liabilities and related deferred taxes. We finalized these fair value adjustments in February 2003, based on

final valuations of property, plant and equipment, intangible assets and other assets and obligations. There were no additional material modifications to the preliminary adjustments from December 31, 2002.

The net purchase price of Orion Power was allocated and the fair value adjustments to the seller's book value were as follows:

	Purchase Price Allocation	Fair Value Adjustments
	(In millions)	
Current assets	$ 636	$ (8)
Property, plant and equipment	3,823	519
Goodwill	1,324	1,220
Other intangibles	477	282
Other long-term assets	103	34
Total assets acquired	6,363	2,047
Current liabilities	(1,777)	(51)
Current contractual obligations	(29)	(29)
Long-term contractual obligations	(86)	(86)
Long-term debt	(1,006)	(45)
Other long-term liabilities	(501)	(396)
Total liabilities assumed	(3,399)	(607)
Net assets acquired	$ 2,964	$1,440

Adjustments to property, plant and equipment and other intangibles, excluding contractual rights, are based primarily on valuation reports prepared by independent appraisers and consultants.

The following factors contributed to the recognized goodwill of $1.3 billion: commercialization value attributable to our trading capabilities, commercialization and synergy value associated with fuel procurement in conjunction with existing generating plants in the region, entry into the New York power market, general and administrative cost synergies with existing PJM Interconnection, LLC (PJM) power market generating assets, and risk diversification value due to increased scale, fuel supply mix and the nature of the acquired assets. Of the resulting goodwill, only $105 million is deductible for United States income tax purposes. The $1.3 billion of goodwill was assigned to the wholesale energy segment. See note 6 for discussion of our subsequent goodwill impairment in 2003 related to our wholesale energy reporting unit.

The components of other intangible assets and the related weighted average amortization period for the Orion Power acquisition consist of the following:

	Purchase Price Allocation	Weighted Average Amortization Period (Years)
	(In millions)	
Air emission regulatory allowances	$314	38
Contractual rights	106	8
Federal Energy Regulatory Commission (FERC) licenses	57	38
Total	$477	

There was no allocation of purchase price to any intangible assets that are not subject to amortization. See note 6 for further discussion of goodwill and intangible assets.

Our results of operations include the results of Orion Power for the period beginning February 19, 2002. The following table presents selected financial information and unaudited pro forma information for 2001 and 2002, as if the acquisition had occurred on January 1, 2001 and 2002, as applicable:

	Year Ended December 31,			
	2001		2002	
	As Reported	Pro forma	As Reported	Pro forma
	(In millions, except per share amounts)			
Revenues	$5,877	$7,033	$10,876	$10,983
Income from continuing operations	461	505	123	59
Income (loss) before cumulative effect of accounting changes	560	604	(326)	(390)
Net income (loss)	563	607	(560)	(624)
Basic earnings per share from continuing operations	$ 1.66	$ 1.82	$ 0.43	$ 0.21
Basic earnings (loss) per share before cumulative effect of accounting changes	2.02	2.18	(1.12)	(1.34)
Basic earnings (loss) per share	2.03	2.19	(1.93)	(2.15)
Diluted earnings per share from continuing operations	$ 1.66	$ 1.82	$ 0.42	$ 0.20
Diluted earnings (loss) per share before cumulative effect of accounting changes	2.02	2.18	(1.12)	(1.34)
Diluted earnings (loss) per share	2.03	2.19	(1.92)	(2.14)

These unaudited pro forma results, based on assumptions we deem appropriate, have been prepared for informational purposes only and are not necessarily indicative of the amounts that would have resulted if the acquisition of Orion Power had occurred on January 1, 2001 and 2002, as applicable. Purchase-related adjustments to the results of operations include the effects on revenues, fuel expense, depreciation and amortization, interest expense, interest income and income taxes. Adjustments that affected revenues and fuel expense were a result of the amortization of contractual rights and obligations relating to the applicable power and fuel contracts that were in existence at January 1, 2002, as applicable. Such amortization included in the pro forma results above was based on the fair value of the contractual rights and obligations at February 19, 2002. The amounts applicable to 2002 were retroactively applied to January 1, 2002 through February 19, 2002 to arrive at the pro forma effect on those periods. The unaudited pro forma condensed interim financial information presented above reflects the acquisition of Orion Power in accordance with SFAS No. 141, "Business Combinations" and SFAS No. 142.

(6) Goodwill and Intangibles

In July 2001, the FASB issued SFAS No. 142, which states that goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and charged to results of operations in periods in which the recorded value of goodwill and certain intangibles with indefinite lives exceeds their fair values. We adopted the provisions of the statement effective January 1, 2002, and discontinued amortizing goodwill into our results of operations. A reconciliation of 2001 reported net income and per share amounts adjusted for the exclusion of goodwill amortization with a comparison to 2002 and 2003 follows:

	Year Ended December 31,		
	2001	2002	2003
	(In millions, except per share amounts)		
Reported net income (loss)	$ 563	$ (560)	$(1,342)
Add: Goodwill amortization for continuing operations, net of tax	25	—	—
Add: Goodwill amortization for discontinued operations, net of tax	26	—	—
Less: Goodwill impairment relating to exiting communications business(1)	(19)	—	—
Adjusted net income (loss)	$ 595	$ (560)	$(1,342)
Basic earnings (loss) per share:			
Reported net income (loss)	$2.03	$(1.93)	$ (4.57)
Add: Goodwill amortization for continuing operations, net of tax	0.09	—	—
Add: Goodwill amortization for discontinued operations, net of tax	0.09	—	—
Less: Goodwill impairment relating to exiting communications business(1)	(0.07)	—	—
Adjusted basic earnings (loss) per share	$2.14	$(1.93)	$ (4.57)
Diluted earnings (loss) per share:			
Reported net income (loss)	$2.03	$(1.92)	$ (4.57)
Add: Goodwill amortization for continuing operations, net of tax	0.09	—	—
Add: Goodwill amortization for discontinued operations, net of tax	0.09	—	—
Less: Goodwill impairment relating to exiting communications business(1)	(0.07)	—	—
Adjusted diluted earnings (loss) per share	$2.14	$(1.92)	$ (4.57)

(1) This impairment of $19 million, net of tax, is included in the annual goodwill amortization amount, net of tax, of $25 million for continuing operations.

Intangibles. Other intangible assets consist of the following:

	Weighted Average Amortization Period (Years)	December 31, 2002 Carrying Amount	December 31, 2002 Accumulated Amortization	December 31, 2003 Carrying Amount	December 31, 2003 Accumulated Amortization
		(In millions)			
Air emission regulatory allowances	36	$586	$(120)	$652	$(168)
Contractual rights	8	106	(26)	105	(54)
Power generation site permits	35	77	(6)	75	(6)
Water rights	35	68	(6)	68	(8)
FERC licenses	38	57	(1)	57	(3)
Other	5	5	(3)	3	(2)
Total		$899	$(162)	$960	$(241)

We recognize specifically identifiable intangibles, including air emissions regulatory allowances, contractual rights, power generation site permits, water rights and FERC licenses, when specific rights and contracts are acquired. We have no intangible assets with indefinite lives recorded as of December 31, 2002 and 2003. We amortize air emissions regulatory allowances primarily on a units-of-production basis as utilized. We amortize other acquired intangibles, excluding contractual rights, on a straight-line basis over the lesser of their contractual or estimated useful lives. All intangibles, excluding goodwill, are subject to amortization.

Estimated amortization expense, excluding contractual rights and obligations (see below), for the next five years is as follows (in millions):

2004	$ 55
2005	30
2006	25
2007	23
2008	20
Total	$153

In connection with the acquisition of Orion Power, we recorded the fair value of certain fuel and power contracts acquired. We estimated the fair value of the contracts using forward pricing curves as of the acquisition date over the life of each contract. Those contracts with positive fair values at the date of acquisition (contractual rights) were recorded to intangible assets and those contracts with negative fair values at the date of acquisition (contractual obligations) were recorded to other long-term liabilities in the consolidated balance sheet.

Contractual rights and contractual obligations are amortized to fuel expense and revenues, as applicable, based on the estimated realization of the fair value established on the acquisition date over the contractual lives. There may be times during the life of the contract when accumulated amortization exceeds the carrying value of the recorded assets or liabilities due to the timing of realizing the fair value established on the acquisition date.

We amortized $26 million and $29 million of contractual rights and contractual obligations, respectively, for a net amount of $3 million, during 2002. We amortized $28 million and $33 million of contractual rights and contractual obligations, respectively, for a net amount of $5 million, during 2003.

Estimated amortization of contractual rights and contractual obligations, excluding Liberty's terminated tolling agreement (see notes 9(a) and 15(c)), for the next five years is as follows:

	Contractual Rights	Contractual Obligations	Net Increase in Income
		(In millions)	
2004	$17	$(31)	$14
2005	—	(9)	9
2006	—	(3)	3
2007	—	(1)	1
2008	—	(1)	1
Total	$17	$(45)	$28

Goodwill. The following tables show the composition of goodwill by reportable segment as of December 31, 2002 and 2003 and changes in the carrying amount of goodwill for 2002 and 2003 by reportable segment:

	Retail Energy	Wholesale	Total
		(In millions)	
As of January 1, 2002	$32	$ 184	$ 216
Goodwill acquired during the period	—	1,324	1,324
Other	—	1	1
As of December 31, 2002	32	1,509	1,541
Impairment(1)	—	(985)	(985)
Transfer to discontinued operations(2)	—	(63)	(63)
Other(3)	21	(31)	(10)
As of December 31, 2003	$53	$ 430	$ 483

(1) See below for discussion.

(2) On July 9, 2003, we entered into a definitive agreement to sell our 588-megawatt Desert Basin plant (see note 23). The sale closed in October 2003. This anticipated sale of our Desert Basin plant operations required us, in accordance with SFAS No. 142, to allocate a portion of the goodwill in the wholesale energy reporting unit to the Desert Basin plant operations on a relative fair value basis as of July 2003 in order to compute the gain or loss on disposal. We did not allocate any goodwill to our Desert Basin plant operations, which are classified as discontinued operations, prior to July 2003.

(3) Effective January 1, 2003, as we began reporting our ERCOT generation facilities in our retail energy segment rather than our wholesale energy segment, we transferred $25 million of goodwill to our retail energy segment. Effective December 31, 2003, we began reporting these facilities in our wholesale energy segment and transferred $4 million of goodwill back to our wholesale energy segment for a net transfer to our retail energy segment of $21 million. See note 21.

As of December 31, 2002 and 2003, we had $144 million and $131 million, respectively, of net goodwill recorded in our consolidated balance sheets that is deductible for United States income tax purposes for future periods.

SFAS No. 142 requires goodwill to be tested at least annually and more frequently in certain circumstances. The date of our annual impairment test was November 1 for 2002 and 2003. A goodwill impairment test is performed in two steps. The initial step is designed to identify potential goodwill impairment by comparing an estimate of the fair value of the applicable reporting unit to its carrying value, including goodwill. If the carrying value exceeds the fair value, a second step is performed, which compares the implied fair value of the applicable reporting unit's goodwill with the carrying amount of that goodwill, to measure the amount of the goodwill impairment, if any.

Goodwill Impairment Transition Test. During the third quarter of 2002, we completed the transitional goodwill impairment test required by SFAS No. 142, including the review of goodwill for impairment as of January 1, 2002. Based on our transitional impairment test, we recorded an impairment of our European energy segment's goodwill of $234 million, net of tax. This impairment loss was recorded retroactively as a cumulative effect of a change in accounting principle in the first quarter of 2002. Based on the first step of this goodwill impairment test, no goodwill was impaired for our other reporting units.

The circumstances leading to the goodwill impairment of our European energy operations included a significant decline in electric margins attributable to the deregulation of the European electricity market in 2001, lack of growth in the wholesale energy trading markets in Northwest Europe, continued regulation of certain European fuel markets and the reduction of proprietary trading in our European operations. Our measurement of the fair value of the European energy operations was based on a weighted average approach considering both an income approach, using future discounted cash flows, and a market approach, using acquisition multiples, including price per MW, based on publicly available data for recently completed European transactions.

2002 Annual Goodwill Impairment Test. We performed our annual impairment test in 2002 effective November 1, 2002. In estimating the fair value of our European energy segment for the annual impairment test, we considered the sales price in the agreement that we signed in February 2003 to sell our European energy operations (see note 22). We concluded that the sales price reflected the best estimate of fair value of our European energy segment as of November 1, 2002, to use in such impairment test. Our annual impairment test determined that the full amount of our European energy segment's net goodwill of $482 million was impaired and such impairment was recorded in the fourth quarter of 2002. For additional information regarding this transaction and its impacts, see note 22. Our 2002 annual impairment test identified no other impairments of goodwill for our other reporting units.

July 2003 Goodwill Impairment Test Related to our Wholesale Energy Segment. On July 9, 2003, we entered into a definitive agreement to sell our 588-megawatt Desert Basin plant. The sale closed in October 2003. See note 23 for further discussion of this sale. This sale of our Desert Basin plant required us to allocate a portion of the goodwill in the wholesale energy reporting unit to the Desert Basin plant operations on a relative fair value basis as of July 2003 in order to compute the gain or loss on disposal. We were also required to test the recoverability of goodwill in our remaining wholesale energy reporting unit as of July 2003.

As a result of the July 2003 test, we recognized an impairment of $985 million (pre-tax and after-tax) in the third quarter of 2003. This impairment was due to a decrease in the estimated fair value of our wholesale energy reporting unit. This change in fair value was primarily due to: reduced projected commercialization opportunities related to our power generation assets; the elimination of proprietary trading; lower projected regulatory capacity values due to the lack of development of appropriate market structures and a lower outlook for revenues from existing regulatory capacity markets; reduced long-term margins from our existing portfolio as a result of lowering our estimates of the margins required to induce new capacity to enter the markets; expectations for the retirement and/or mothballing of some of our facilities; lower market and comparable public company values data; and the level of working capital; partially offset by reductions in our projected commercial, operational and support groups costs and lower projected operations and maintenance expense.

2003 Annual Goodwill Impairment Tests. We performed our annual goodwill impairment tests for our wholesale energy and retail energy reporting units effective November 1, 2003 and determined that no additional impairments of goodwill had occurred since July 2003.

Estimation of our Wholesale Energy Segment Fair Value. We estimate the fair value of our wholesale energy segment based on a number of subjective factors, including: (a) appropriate weighting of

valuation approaches (income approach, market approach and comparable public company approach), (b) projections about future power generation margins, (c) estimates of our future cost structure, (d) discount rates for our estimated cash flows, (e) selection of peer group companies for the public company approach, (f) required level of working capital, (g) assumed terminal value and (h) time horizon of cash flow forecasts.

The income approach used in our analyses is a discounted cash flow analysis based on our internal forecasts and contains numerous assumptions made by management and the independent appraiser, any of which if changed could significantly affect the outcome of the analyses. We believe the income approach is the most subjective of the approaches.

Management has determined the fair value of our wholesale energy reporting unit with the assistance of an independent appraiser. In determining the fair value of our wholesale energy segment in 2003, we made the following key assumptions: (a) the markets in which we operate will continue to be deregulated; (b) demand for electricity will grow, which will result in lower reserve margins; (c) there will be a recovery in electricity margins over time to a level sufficient such that companies building new generation facilities can earn a reasonable rate of return on their investment and (d) the economics of future construction of new generation facilities will likely be driven by regulated utilities. As part of our process, we modeled all of our power generation facilities and those of others in the regions in which we operate. The following table summarizes certain of these significant assumptions:

	January 2002	November 2002	July 2003	November 2003
Number of years used in internal cash flow analysis(1)	5	15	15	15
EBITDA multiple for terminal values(2)	6.0	7.0 to 7.5	7.5	7.5
Risk-adjusted discount rate for our estimated cash flows	9.0%	9.0%	9.0%	9.0%
Average anticipated growth rate for demand in power(3)	2.0%	2.0%	2.0%	2.0%
After-tax return on investment for new investment(4)	9.0%	9.0%	7.5%	7.5%

(1) The number of years used in the internal cash flow analysis changed from 5 years in the January 2002 test to 15 years due to the fact that five years in the forecast did not capture the full impact of the cyclical nature of our wholesale energy operations. Additional periods were included in the forecasts to derive an appropriate forecast period, which was used to determine the estimated terminal value. As of January 2002, based on current market conditions in the wholesale energy industry, management did not believe additional periods beyond five years in the forecast were required.

(2) The EBITDA multiple for terminal values changed from 6.0 in the January 2002 test to 7.0 to 7.5 in the November 2002 test and from 7.0 to 7.5 in the November 2002 test to 7.5 in the 2003 tests due to the independent appraiser's updated analysis of the public guideline companies that indicated higher multiples were appropriate to calculate the terminal values at the applicable dates.

(3) Depending on the region, the specific rate is projected to be somewhat higher or lower.

(4) Based on our assumption in 2003 that regulated utilities will be the primary drivers underlying the construction of new generation facilities, we have assumed that the after-tax return on investment will yield a return representative of a regulated utility's cost of capital (7.5%) rather than that of an independent power producer (9.0%). Based on changes in assumed market conditions, including regulatory rules, we have changed the projected time horizon for substantially achieving the after-tax return on investment to 2008 — 2012 (depending on region). Formerly, we had assumed that the time horizon for substantially achieving this rate of return was 2006 — 2010.

Potential Future Impairments of Goodwill. Because we recognized a goodwill impairment in 2003, in the near future, if our wholesale energy market outlook changes negatively, we could have additional impairments of goodwill that would need to be recognized. In addition, our ongoing evaluation of our wholesale energy business could result in decisions to mothball, retire or dispose of additional generation assets, any of which could result in additional impairment charges related to goodwill, impact our fixed assets' depreciable lives or result in fixed asset impairment charges.

(7) Derivative Instruments, Including Energy Trading Activities

We are exposed to various market risks. These risks arise from the ownership of our assets and operation of our business. We routinely 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 interest rate swaps and options to mitigate the impact of changes in interest rates and other financial instruments to manage various other market risks.

We have a risk control framework designed to monitor, measure and define appropriate transactions to hedge and manage the risk in our existing portfolio of assets and contracts and to authorize new transactions. These risks fall into three different categories: market risk, credit risk and operational risk. We believe that we have effective procedures for evaluating and managing these risks to which we are exposed. Key risk control activities include definition of appropriate transactions for hedging, 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, value-at-risk 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.

The primary types of derivatives we use are described below:

- Futures contracts are exchange-traded standardized commitments to purchase or sell an energy commodity or financial instrument, or to make a cash settlement, at a specific price and future date.
- Physical forward contracts are commitments to purchase or sell energy commodities in the future.
- Swap agreements require payments to or from counterparties based upon the differential between a fixed price and variable index price (fixed price swap) or two variable index prices (variable price swap) for a predetermined contractual notional amount. The respective index may be an exchange quotation or an industry pricing publication.
- Option contracts convey the right to buy or sell an energy commodity or a financial instrument at a predetermined price or settlement of the differential between a fixed price and a variable index price or two variable index prices.

Trading and derivative assets and liabilities at December 31, 2002 and 2003 include amounts for non-trading and trading activities, as follows:

	Assets		Liabilities		Net Assets (Liabilities)
	Current	Long-term	Current	Long-term	
			(In millions)		
December 31, 2002:					
Non-trading activities:					
Cash flow hedges — offset to accumulated other comprehensive income (loss):					
Commodity	$1,260	$ 370	$(1,191)	$(393)	$ 46
Interest	—	—	(29)	(36)	(65)
Total	1,260	370	(1,220)	(429)	(19)
Derivatives marked to market through earnings	24	28	(45)	(34)	(27)
Total	1,284	398	(1,265)	(463)	(46)
Trading activities	3,866	880	(3,736)	(811)	199
Set-off adjustments	(4,484)	(1,014)	4,484	1,014	—
Total trading and derivative assets and liabilities	$ 666	$ 264	$ (517)	$(260)	$153
December 31, 2003:					
Non-trading activities:					
Cash flow hedges — offset to accumulated other comprehensive income (loss):					
Commodity	$ 828	$ 284	$ (668)	$(304)	$140
Interest	—	3	(26)	(22)	(45)
Total	828	287	(694)	(326)	95
Derivatives marked to market through earnings	399	58	(378)	(53)	26
Total	1,227	345	(1,072)	(379)	121
Trading activities	1,099	529	(1,118)	(511)	(1)
Set-off adjustments	(1,833)	(674)	1,833	674	—
Total trading and derivative assets and liabilities	$ 493	$ 200	$ (357)	$(216)	$120

(a) Non-Trading Derivative Activities.

To reduce the risk from market fluctuations in our results of operations and the resulting cash flows, we may enter into energy derivatives in order to hedge some expected purchases of electric power, natural gas and other commodities and sales of electric power (non-trading energy derivatives). The non-trading energy derivative portfolios are managed to complement our asset portfolio, reducing overall risks.

The fair values of our non-trading derivative activities as of December 31, 2002 and 2003, are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

Below is the pre-tax income (loss) of our non-trading derivative instruments, including non-trading energy derivatives and interest rate derivatives, both from cash flow hedge ineffectiveness and from non-trading derivative mark-to-market income and losses, for 2001, 2002 and 2003:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Hedge ineffectiveness(1)	$28	$(17)	$(20)
Non-trading derivatives mark-to-market income (loss)(2)	(2)	(11)	(19)
Total	$26	$(28)	$(39)

(1) For 2001, 2002 and 2003, no component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness.

(2) Includes $0, $16 million and $0 for 2001, 2002 and 2003, respectively, of losses recognized in our results of operations as a result of the discontinuance of cash flow hedges because it was probable that the forecasted transaction would not occur.

Below is a reconciliation of our net derivative assets (liabilities) to accumulated other comprehensive loss, net of tax, as of December 31, 2002 and 2003:

	As of December 31,	
	2002	2003
	(In millions)	
Net non-trading derivative assets (liabilities)	$(46)	$121
Non-trading commodity derivatives not designated as cash flow hedges	10	3
Non-trading interest rate caps not designated as cash flow hedges	—	(20)
Recognized cash flow hedge ineffectiveness	(27)	(8)
Cash flow hedges terminated prior to maturity	(8)	(11)
Terminated interest rate swaps	(38)	(38)
Deferred tax assets attributable to accumulated other comprehensive loss on cash flow hedges	22	21
Net assets transferred to non-trading derivatives due to implementation of EITF No. 02-03	—	(27)
Deferred options premium	22	(78)
Accumulated other comprehensive income (loss) from equity investments	—	(2)
Accumulated other comprehensive loss from derivative instruments, net of tax(1)(2)	$(65)	$(39)

(1) Represents deferred derivative losses of our total accumulated other comprehensive loss.

(2) As of December 31, 2003, we expect $21 million of accumulated other comprehensive loss to be reclassified into our results of operations during 2004.

As of December 31, 2002 and 2003, the maximum length of time we are hedging our exposure to the variability in future cash flows for forecasted transactions, excluding the payment of variable interest on existing financial instruments, is ten years and nine years, respectively. As of December 31, 2002 and 2003,

the maximum length of time we are hedging our exposure to the payment of variable interest rates is seven and six years, respectively.

For a discussion of our interest rate derivative instruments, see note 9(c).

Other Non-trading Derivative Activities. During 2001, we entered into two structured transactions, involving a series of forward contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002. The change in fair value of these derivative assets and liabilities was recorded in the statement of consolidated operations for each reporting period. During 2001 and 2002, $117 million of net non-trading derivative liabilities and $121 million of net non-trading derivative assets, respectively, were settled related to these transactions, which was recorded in cash flows from operations; $1 million and $3 million, respectively, of pre-tax unrealized gains were recognized.

(b) Energy Trading Activities.

As discussed in note 2(d), in March 2003, we discontinued our proprietary business. Trading positions taken prior to our decision to exit this business are managed solely for purposes of closing them on economical terms.

Historically, our trading activities included (a) transactions establishing open positions in the energy markets, primarily on a short-term basis and (b) energy price risk management services to customers primarily related to natural gas, electric power and other energy-related commodities. Our electricity sales to large commercial, industrial and institutional customers under contracts executed before October 25, 2002 were accounted for under the mark-to-market method of accounting upon contract execution (see note 2(d)).

The fair values of our trading activities as of December 31, 2002 and 2003, are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

During 2001, 2002 and 2003, we recognized a loss of $23 million, income of $31 million and income of $11 million, respectively, for changes in the fair values of trading assets/liabilities due to changes in valuation techniques and assumptions.

As of December 31, 2003, the weighted average term of the trading portfolio, based on fair values, is approximately 16 months. The maximum term of any contract in the trading portfolio is 13 years. These maximum and average terms are not indicative of likely future cash flows, as these positions may be changed by new transactions in the trading portfolio at any time in response to changing risk management portfolio strategies. Terms regarding cash settlements of these contracts vary with respect to the actual timing of cash receipts and payments.

(c) Credit Risk.

Credit risk is inherent in our commercial activities and relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. We have broad credit policies and parameters. We seek to enter into contracts that permit us to net receivables and payables with a given counterparty. We also enter into contracts that enable us to obtain collateral from a counterparty as well as to terminate upon the occurrence of certain events of default. The credit risk control organization establishes counterparty credit limits. We employ tiered levels of approval authority for counterparty credit limits, with authority increasing from the credit risk control organization through senior management. Credit risk exposure is monitored daily and the financial condition of our counterparties is reviewed periodically.

If any of our counterparties failed to perform, we might be forced to acquire alternative hedging arrangements or be required to replace the underlying commitment at then-current market prices. In this

event, we might incur additional losses in addition to amounts owed to us by the counterparty. For information regarding the provision related to energy sales in California, see note 15(b). For information regarding the net provision recorded in 2001 related to energy sales to Enron, see note 15(a).

As of December 31, 2002 and 2003, one non-investment grade counterparty represented 14% and 18% of our total credit exposure, net of collateral. The dollar amounts of our credit exposure to this one counterparty were $86 million and $113 million as of December 31, 2002 and 2003, respectively. There were no other counterparties representing greater than 10% of our total credit exposure, net of collateral.

(8) Equity Investments

We own a 50% interest in a 470 MW electric generation plant in Boulder City, Nevada. We also own a 50% interest in a 108 MW cogeneration plant in Orange, Texas. These equity investments are included in our wholesale energy segment.

Our equity investments are as follows:

	December 31,	
	2002	2003
	(In millions)	
Nevada generation plant	$ 73	$66
Texas cogeneration plant	30	29
Equity investments	$103	$95

Our income (loss) from equity investments is as follows:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Nevada generation plant	$5	$16	$(5)
Texas cogeneration plant	2	2	3
Income (loss) of equity investments	$7	$18	$(2)

During 2001, 2002 and 2003, the net distributions were $27 million, $3 million and $4 million, respectively, from these investments.

As of December 31, 2002 and 2003, the companies in which we have an equity investment carry debt, of $145 million and $134 million, respectively ($73 million and $67 million, respectively, based on our proportionate ownership interests of the investments). This debt is non-recourse to Reliant Resources and all of its consolidated subsidiaries.

(9) Credit Facilities, Bonds, Notes and Other Debt

The following table presents our debt outstanding to third parties as of December 31, 2002 and 2003:

	December 31,					
	2002			2003		
	Weighted Average Stated Interest Rate(1)	Long-term	Current(2)	Weighted Average Stated Interest Rate(1)	Long-term	Current(2)
	(In millions, except interest rates)					
Banking or Credit Facilities, Bonds and Notes						
Other Operations Segment:						
Senior secured term loans	—	$ —	$ —	5.27%	$1,785	$ —
Senior secured revolver	—	—	—	5.58	183	—
Senior secured notes — 2010	—	—	—	9.25	550	—
Senior secured notes — 2013	—	—	—	9.50	550	—
Convertible senior subordinated notes	—	—	—	5.00	275	—
Orion acquisition term loan	3.68%	2,908(3)	—(3)	—	—	—
364-day revolver/term loan	3.20	800(3)	—(3)	—	—	—
Three-year revolver	3.13	208(3)	350(3)	—	—	—
Wholesale Energy Segment:						
Orion Power Holdings and Subsidiaries:						
Orion Power Holdings senior notes	12.00	400	—	12.00	400	—
Orion MidWest and Orion NY term loans	3.96	1,211	109	3.93	1,093	125
Orion MidWest revolving working capital facility	3.92	—	51	—	—	—
Orion NY revolving working capital facility	—	—	—	—	—	—
Liberty credit agreement:						
Floating rate debt	3.02	—	103(4)	2.40	—	97(4)
Fixed rate debt	9.02	—	165(4)	9.02	—	165(4)
PEDFA bonds for Seward plant	—	—	—	1.27	400	—
REMA term loans	—	—	—	4.19	28	14
Reliant Energy Channelview, L.P.:						
Term loans and revolving working capital facility:						
Floating rate debt	2.81	290	9	2.54	283	7
Fixed rate debt	9.55	75	—	9.55	75	—
Total facilities, bonds and notes		5,892	787		5,622	408
Other						
Adjustment to fair value of debt(5)	—	66	8	—	58	8
Adjustment to fair value of interest rate swaps(5)	—	46	19	—	34	13
Adjustment to fair value of debt due to warrants	—	—	—	—	(6)	(2)
Other — wholesale energy segment	6.20	1	—	6.20	1	—
Other — retail energy segment	5.41	4	6	5.41	—	4
Total other debt		117	33		87	23
Total debt		$6,009	$ 820		$5,709	$431

(1) The weighted average stated interest rates are for borrowings outstanding as of December 31, 2002 or 2003, as applicable.

(2) Includes amounts due within one year of the date noted, as well as loans outstanding under revolving and working capital facilities classified as current liabilities.

(3) See below for a discussion of the facilities refinanced in March 2003. As a result of the refinancing, $3.9 billion has been classified as long-term as of December 31, 2002.

(4) The entire balance outstanding under this credit agreement has been classified as current as of December 31, 2002 and 2003. Included in the outstanding amount as of December 31, 2003, is $2 million and $2 million of scheduled principal payments, which were due in October 2003 and January 2004, respectively, for which no payment has been made. As interest payments due in October 2003 and January 2004 were deferred, additional interest will be charged on the past due interest amounts. Of the amount shown as current under the Liberty credit agreement, $11 million matures within 12 months of December 31, 2003. See below and note 15(c) for further discussion.

(5) Debt and interest rate swaps acquired in the Orion Power acquisition were adjusted to fair market value as of the acquisition date. Included in the adjustment to fair value of debt is $74 million and $66 million related to the Orion Power Holdings senior notes as of December 31, 2002 and 2003, respectively. Included in the adjustment to fair value of interest rate swaps is $42 million and $23 million related to the Orion Power MidWest, L.P. (Orion MidWest) and Orion Power New York, L.P. (Orion NY) credit facilities, respectively, as of December 31, 2002. Included in the adjustment to fair value of interest rate swaps is $28 million and $19 million related to the Orion MidWest and Orion NY credit facilities, respectively, as of December 31, 2003. Included in interest expense is amortization of $5 million and $8 million for valuation adjustments for debt and $25 million and $18 million for valuation adjustments for interest rate swaps, respectively, for 2002 and 2003, respectively. These valuation adjustments are being amortized over the respective remaining terms of the related financial instruments.

Restricted Net Assets of Subsidiaries. Certain of Reliant Resources' subsidiaries have effective restrictions on their ability to pay dividends or make intercompany loans and advances pursuant to their financing arrangements. The amount of restricted net assets of Reliant Resources' subsidiaries as of December 31, 2003 is approximately $2.8 billion. Such restrictions are on the net assets of Orion Power Capital, LLC (Orion Capital), Liberty and Channelview. Orion MidWest and Orion NY are subsidiaries of Orion Capital.

Maturities. As of December 31, 2003, maturities of all facilities and other debt were as follows (in millions):

2004	$ 161(1)
2005	1,126(1)
2006	38(1)
2007	1,994(1)
2008	28(1)
2009 and thereafter	2,688(1)
Subtotal	6,035
Other items included in debt	105
Total debt	$6,140

(1) Included in the amounts for years 2004, 2005, 2006, 2007, 2008 and 2009 and thereafter are $11 million, $9 million, $10 million, $10 million, $11 million and $211 million, respectively, related to our Liberty credit agreement and which have all been classified as current liabilities in our consolidated balance sheet as of December 31, 2003. See below and note 15(c) for further discussion.

Debt Covenant Compliance. We were in compliance with all of our debt covenants as of December 31, 2003, other than under the Liberty credit agreement. See below for further discussion.

(a) Banking or Credit Facilities, Bonds and Notes.

The following table provides a summary of the amounts owed and amounts available as of December 31, 2003 under our various committed credit facilities, bonds and notes:

	Total Committed Credit	Drawn Amount	Letters of Credit	Unused Amount	Commitments Expiring By December 31, 2004	Principal Amortization and Commitment Expiration Date
			(In millions)			
Other Operations Segment:						
Senior secured term loans	$1,785	$1,785	$ —	$ —	$ —	March 2007
Senior secured revolver	2,100	183	869(1)	1,048	—	March 2007
Senior secured notes — 2010	550	550	—	—	—	July 2010
Senior secured notes — 2013	550	550	—	—	—	July 2013
Convertible senior subordinated notes	275	275	—	—	—	August 2010
Wholesale Energy Segment:						
Orion Power Holdings and Subsidiaries:						
Orion Power Holdings senior notes	400	400	—	—	—	May 2010
Orion MidWest and Orion NY term loans	1,218	1,218	—	—	125	March 2004 — October 2005
Orion MidWest revolving working capital facility	75	—	16	59	—	October 2005
Orion NY revolving working capital facility	30	—	7	23	—	October 2005
Liberty credit agreement	284	262	17(2)	5(3)	11	January 2004 — April 2026
PEDFA bonds for Seward plant	400	400	—	—	—	December 2036
REMA term loans	42	42	—	—	14	January 2004 — July 2006
Reliant Energy Channelview LP:						
Term loans and revolving working capital facility	379	365	—	14	7	January 2004 — July 2024
Total	$8,088	$6,030	$909	$1,149	$157	

(1) Included in this amount is $407 million of letters of credit outstanding that support the $400 million of PEDFA bonds related to the Seward plant.

(2) With consent of the lenders, we have chosen to defer the principal and interest payments due October 2003 rather than draw on the $17 million letter of credit posted as debt service reserve. See below and note 15(c) for further discussion.

(3) As discussed below and in note 15(c), this amount is currently not available to Liberty.

As of December 31, 2003, committed credit facilities and notes aggregating $717 million were unsecured.

Senior Secured Term Loans and Senior Secured Revolver. During March 2003, we refinanced our (a) $1.6 billion senior revolving credit facilities, (b) $2.9 billion 364-day Orion acquisition term loan, and (c) $1.425 billion construction agency financing commitment (see note 14(b)). The syndicated bank refinancing combined the existing credit facilities into a $2.1 billion senior secured revolving credit facility, a $921 million senior secured term loan and a $2.91 billion senior secured term loan. The loans under the refinanced credit facilities bear interest at the London inter-bank offered rate (LIBOR) plus 4.0% or a base rate plus 3.0%.

In connection with our March 2003 refinancing, we entered into a $300 million senior priority facility. Borrowings under this facility were limited to secure or prepay ongoing commercial and hedging obligations.

The senior secured facilities originally totaling $5.93 billion are secured with a lien on all of our contractually and legally available assets. With the exception of subsidiaries prohibited by the terms of their financing documents from doing so, our subsidiaries guarantee the refinanced credit facilities.

In connection with our March 2003 refinancing, we issued 20,373,326 warrants, of which 12,537,432 warrants have subsequently been canceled, to acquire shares of our common stock. The remaining 7,835,894 warrants, which have an exercise price of $5.09 per share, vested in March 2003 and are exercisable until August 2008. See (b) below for further discussion.

Our March 2003 credit facilities include restrictions on our ability to take specific actions, subject to numerous exceptions that are designed to allow for the execution of our business plans in the ordinary course. Such restrictions include our ability to (a) encumber our assets, (b) enter into business combinations or divest our assets, (c) incur additional debt or engage in sale and leaseback transactions, (d) pay dividends or prepay certain other debt, (e) make investments or acquisitions or engage in development activities, (f) enter into transactions with affiliates, (g) make capital expenditures, (h) materially change our business, (i) amend our debt and other material agreements, (j) repurchase our capital stock, (k) allow limitations on distributions from our subsidiaries and (l) engage in certain types of trading activities. We must use the proceeds of any loans under the senior secured revolving credit facility solely for working capital and other general corporate purposes and we are not permitted to use the proceeds from loans under any of these facilities to acquire Texas Genco or ERCOT assets. Financial covenants include maintaining a debt to earnings before interest, taxes, depreciation, amortization and rent (EBITDAR) ratio of a certain minimum amount and an EBITDAR to interest ratio of a certain minimum amount. We must be in compliance with each of the covenants before we can borrow or issue letters of credit under the revolving credit facility. The covenants are not anticipated to materially restrict our ability to borrow funds or obtain letters of credit. Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the revolving credit commitment being canceled and/or our being required to repay these borrowings before their scheduled due dates. We must also prepay the refinanced facilities with net proceeds from certain asset sales and issuances of certain debt and equity securities and, beginning in 2005, with certain cash flows in excess of a threshold amount.

In connection with our July 2003 issuance of senior secured notes, described below, we entered into an amendment to our March 2003 credit facilities to, among other things, permit the sharing of collateral with those notes and certain future indebtedness and increase our flexibility to purchase CenterPoint's interest in Texas Genco. The amendment allows us to negotiate a purchase of CenterPoint's interest in the common stock of Texas Genco outside the option and also extends the deadline for agreeing to make the purchase until September 15, 2004. The amendment also revised the collateral mechanics to replace the collateral agent with a collateral trustee for the benefit of the banks and the holders of other secured indebtedness, including the holders of the senior secured notes, revised the mandatory prepayment provisions so that the senior secured notes may share pro rata with the banks any net proceeds from asset sales required to be paid to the banks (other than proceeds from the sale of our Desert Basin plant and our European energy operations) and separated the Orion Power Holdings limited guarantee from the credit agreement so it can ratably guarantee the bank debt and the senior secured notes.

We finalized a second amendment to our March 2003 credit facilities in December 2003. In connection with this amendment, we used $917 million that had accumulated in an escrow account, including the net proceeds from (a) primarily the sales of our Desert Basin plant and our European energy operations and the related interest income ($651 million) and (b) our convertible senior subordinated

notes ($266 million), to prepay debt under the credit facilities. The December 2003 amendment continues to allow us, by specified dates, to purchase the stock of Texas Genco through a negotiated purchase with CenterPoint and adds the flexibility, with certain limitations, to purchase up to $1.0 billion of individual generating assets from Texas Genco or others to support our Texas retail business, and to raise specified forms of debt to finance such asset acquisitions. In connection with this amendment, we also canceled our $300 million senior priority facility, which was never used. If we later determine that this facility is needed, the December 2003 amendment gives us the flexibility to obtain a new senior priority facility, for the same purposes and with the same priority or equal priority with the lenders under our March 2003 credit facilities and our senior secured notes, in an amount up to $300 million.

After the December 2003 amendment, our March 2003 credit facilities permit us to place net cash proceeds from offerings of junior securities in a restricted escrow account for the possible acquisition of the stock of Texas Genco or of individual generating assets from Texas Genco or others to support our Texas retail business. If such cash proceeds are not used for such acquisitions, we may keep up to 50% of the cash proceeds for general corporate purposes and are required to use the remainder to prepay indebtedness under our March 2003 credit facilities.

Senior Secured Notes. On July 1, 2003, we issued $550 million 9.25% senior secured notes and $550 million 9.5% senior secured notes and received net proceeds, after deducting the initial purchasers' discount and estimated out-of-pocket expenses, of $1.056 billion. We used the net proceeds of the issuance to prepay $1.056 billion of senior secured term loans under our March 2003 credit facilities. Interest is payable semi-annually on January 15 and July 15. With certain limited exceptions, the senior secured notes are secured by the same collateral which secures our March 2003 credit facilities. The collateral is held by a collateral trustee under a collateral trust agreement for the ratable benefit of all holders of the credit agreement debt, senior secured note holders and holders of certain future secured indebtedness. The senior secured notes are also guaranteed by all of our subsidiaries that guarantee our March 2003 credit facilities, except for certain subsidiaries of Orion Power Holdings and certain other subsidiaries. See note 19 for further discussion of the guarantors, the limited guarantor and the non-guarantors. The senior secured notes indentures contain covenants that include, among others, restrictions on (a) the payment of dividends, (b) the incurrence of indebtedness and the issuance of preferred stock, (c) investments, (d) asset sales, (e) liens, (f) transactions with affiliates, (g) our ability to amend the subordination provisions of our convertible senior subordinated notes, (h) engaging in unrelated businesses and (i) sale and leaseback transactions. These covenants are not expected to materially restrict our ability to conduct our business.

Convertible Senior Subordinated Notes. In June and July 2003, we issued $275 million aggregate principal amount of convertible senior subordinated notes and received net proceeds, after deducting the initial purchasers' discount and estimated out-of-pocket expenses, of $266 million. In connection with the December 2003 amendment to our March 2003 credit facilities, as discussed above, we used these net proceeds to prepay debt under our March 2003 credit facilities. The notes bear interest at 5.00% per annum, payable semi-annually on February 15 and August 15. The notes are convertible into shares of our common stock at a conversion price of approximately $9.54 per share, subject to adjustment in certain circumstances. We may redeem the notes, in whole or in part, at any time on or after August 20, 2008, if the last reported sale price of our common stock is at least 125% of the conversion price then in effect for a specified period of time.

Orion Power Holdings Senior Notes. Orion Power Holdings has outstanding $400 million aggregate principal amount of 12% senior notes. In connection with the Orion Power acquisition, we recorded the senior notes at an estimated fair value of $479 million. The $79 million premium is being amortized to interest expense using the effective interest rate method over the life of the senior notes. The fair value of the senior notes was based on our incremental borrowing rates for similar types of borrowing arrangements

as of the acquisition date. The senior notes are senior unsecured obligations of Orion Power Holdings. Orion Power Holdings is not required to make any mandatory redemption or sinking fund payments with respect to the senior notes. The senior notes are not guaranteed by any of Orion Power Holdings' subsidiaries and are non-recourse to Reliant Resources. The senior notes indenture contains covenants, which bind Orion Power Holdings and certain of its subsidiaries, that include, among others, restrictions on (a) the payment of dividends, (b) the incurrence of indebtedness and the issuance of preferred stock, (c) investments, (d) asset sales, (e) liens, (f) transactions with affiliates, (g) engaging in unrelated businesses and (h) sale and leaseback transactions.

Orion MidWest and Orion NY Credit Agreements. During October 2002, the Orion Power Holdings revolving credit facility was prepaid and terminated, and we refinanced the Orion MidWest and Orion NY credit agreements. In connection with these refinancings, we applied excess cash of $145 million to prepay and terminate the Orion Power Holdings revolving credit facility and to reduce the term loans and revolving working capital facilities at Orion MidWest and Orion NY. As of the refinancing date, the amended and restated Orion MidWest credit agreement included a term loan of approximately $974 million and a $75 million revolving working capital facility. As of the refinancing date, the amended and restated Orion NY credit agreement included a term loan of approximately $353 million and a $30 million revolving working capital facility. As of December 31, 2002 and 2003, Orion MidWest had $969 million and $884 million, respectively, of term loans outstanding. As of December 31, 2002 and 2003, Orion NY had $351 million and $334 million, respectively, of term loans outstanding. The refinancing included an extension of the maturities of the Orion MidWest and Orion NY credit agreements by three years to October 2005.

The loans under each facility bear interest at LIBOR plus a margin or at a base rate plus a margin. The LIBOR margin is 2.75% as of December 31, 2003 and increases to 3.25% in April 2004 and 3.75% in October 2004. The base rate margin is 1.75% as of December 31, 2003 and increases to 2.25% in April 2004 and 2.75% in October 2004.

The amended and restated Orion MidWest credit agreement is secured by a first lien on substantially all of the assets of Orion MidWest and its subsidiary. Orion NY and its subsidiaries are guarantors of the Orion MidWest obligations under the amended and restated Orion MidWest credit agreement. A substantial portion of the assets of Orion NY and its subsidiaries (excluding certain plants) are pledged, via a second lien, as collateral for this guarantee. The amended and restated Orion NY credit agreement is, in turn, secured by a first lien on a substantial portion of the assets of Orion NY and its subsidiaries (excluding certain plants). Orion MidWest and its subsidiary are guarantors of the Orion NY obligations under the amended and restated Orion NY credit agreement. Substantially all of the assets of Orion MidWest and its subsidiary are pledged, via a second lien, as collateral for this guarantee. Orion MidWest's and Orion NY's obligations under the respective agreements are non-recourse to Orion Power Holdings and Reliant Resources.

Both the Orion MidWest and Orion NY credit agreements contain affirmative and negative covenants, including negative pledges, that must be met by each borrower under its respective agreement to borrow funds or obtain letters of credit, and which require Orion MidWest and Orion NY to maintain a combined debt service coverage ratio of 1.5 to 1.0. These covenants are not anticipated to materially restrict either borrower's ability to borrow funds or obtain letters of credit. The agreements also provide for any available cash at one borrower to be made available to the other borrower to meet shortfalls in the other borrower's ability to make certain payments, including operating costs. This is effected through distributions of such available cash to Orion Capital, a direct subsidiary of Orion Power Holdings formed in connection with the refinancing. Orion Capital, as indirect owner of each of Orion MidWest and Orion NY, can then contribute such cash to the other borrower. The ability of the borrowers to make dividends, loans or advances to Orion Power Holdings for interest payments or otherwise is restricted. In any event, no

distributions may be made after October 28, 2004 until the earlier of maturity or retirement. No distributions are anticipated during the remaining terms of the credit agreements. Any restricted cash which is not dividended, will be applied on a quarterly basis to prepay outstanding loans at Orion MidWest and Orion NY. See note 2(l) for a detail of restricted cash under the Orion MidWest and Orion NY credit agreements.

Liberty Credit Agreement. In July 2000, Liberty Electric Power, LLC (LEP) and Liberty, indirect wholly-owned subsidiaries of Orion Power Holdings, entered into a credit agreement that provided for (a) a construction/term loan in an amount of up to $105 million, (b) an institutional term loan in an amount of up to $165 million, (c) a debt service reserve letter of credit facility of $17 million, (d) a revolving working capital facility for an amount of up to $5 million and (e) an equity bridge loan of up to $41 million. In May 2002, the construction loans were converted to term loans. On the conversion date, Orion Power Holdings made the required cash equity contribution of $30 million into Liberty, which was used to repay a like amount of equity bridge loans advanced by the lenders. A related $41 million letter of credit furnished by Orion Power Holdings as credit support was canceled.

The floating rate loans under the Liberty credit agreement bear interest at LIBOR plus a margin or a base rate plus a margin. For the floating rate term loan, as of December 31, 2003, the LIBOR margin is 1.25% and increases to 1.375% in May 2005 and 1.625% in May 2008. As of December 31, 2003, the base rate margin is 0.25% and increases to 0.375% in May 2005 and 0.625% in May 2008. For the revolving working capital facility, as of December 31, 2003, the LIBOR margin is 1.25% and increases to 1.375% in May 2005. As of December 31, 2003, the base rate margin is 0.25% and increases to 0.375% in May 2005.

The lenders under the Liberty credit agreement have a security interest in substantially all of the assets of Liberty and LEP. The outstanding borrowings related to the Liberty credit agreement are non-recourse to Reliant Resources and all other subsidiaries. The Liberty credit agreement contains affirmative and negative covenants, including a negative pledge, that must be met to borrow funds or obtain letters of credit. Liberty is currently unable to access the revolving working capital facility. Additionally, the Liberty credit agreement restricts Liberty's ability to, among other things, make dividend distributions unless Liberty satisfies various conditions. See note 2(l) for a detail of restricted cash under the Liberty credit agreement.

Given that Liberty is currently in default under the credit agreement, we have classified the debt as a current liability. Neither Reliant Resources nor any other of its subsidiaries is in default under other debt agreements due to the credit agreement default at Liberty. See note 15(c).

PEDFA Bonds for Seward Plant. One of our wholly-owned subsidiaries is in the process of constructing a 521 MW waste-coal fired, steam electric generation plant located in Pennsylvania. This facility, the Seward project, was directly owned by an entity, which was not consolidated as of December 31, 2002; however, due to our adoption of FIN No. 46, effective on January 1, 2003, we consolidated this entity (see note 2(c)). Three series of tax-exempt revenue bonds relating to the Seward project were issued in December 2001 and April 2002 by the Pennsylvania Economic Development Financing Authority (PEDFA), for a total of $300 million outstanding as of January 1, 2003. In September 2003, an additional $100 million in tax-exempt revenue bonds relating to the Seward project were issued by PEDFA, for a total of $400 million outstanding as of December 31, 2003. Of the net proceeds from the September 2003 issuance, $95 million was used to pay down borrowings under our senior secured revolver. The bonds bear interest, which is payable monthly, at a floating rate determined each week. The bonds are non-recourse to Reliant Resources; however, letters of credit totaling $407 million have been issued under our $2.1 billion senior secured revolver to support the bonds. Upon an event of default under our March 2003 credit facilities, the banks issuing the letters of credit have the right to cause the trustee to accelerate the bonds and draw on the letters of credit.

REMA Term Loans. Reliant Energy Mid-Atlantic Power Holdings, LLC and its subsidiaries' (REMA) is obligated to provide credit support for its lease obligations (see note 14(a)) in the form of letters of credit and/or cash resulting from draws on such letters of credit, equal to an amount representing the greater of (a) the next six months' scheduled rental payments under the related lease or (b) 50% of the scheduled rental payments due in the next 12 months under the related lease. REMA's lease obligations are currently supported by the cash proceeds resulting from the draw in August 2003 on three separate letters of credit and $16 million in letters of credit issued in January 2004. The draw on the letters of credit constituted the making of term loans to REMA by the banks that had issued the letters of credit pursuant to provisions that had been contemplated in the original letter of credit facilities at their inception and did not constitute a default under any of REMA's obligations. Interest on the term loans is payable at the rate of LIBOR plus 3%. REMA's subsidiaries guarantee REMA's obligations under the leases and the term loans. The term loans are non-recourse to Reliant Resources.

Reliant Energy Channelview L.P. In 1999, Channelview, a project subsidiary of Reliant Energy Power Generation, Inc. (REPG), entered into a $475 million syndicated credit facility to finance the construction and start-up operations of an electric power generation plant located in Channelview, Texas. The maximum availability under this facility was (a) $92 million in equity bridge loans for the purpose of paying or reimbursing project costs, (b) $369 million in loans to finance the construction of the project and (c) $14 million in revolving loans for general working capital purposes. In November 2002, the construction loans were converted to term loans. On the conversion date, subsidiaries of REPG contributed cash equity and subordinated debt of $92 million into Channelview, which was used to repay in full the equity bridge loans advanced by the lenders. The term loans have scheduled maturities from 2004 to 2024. The revolving working capital facility matures in 2007.

As of December 31, 2003, with the exception of the fixed-rate tranche, the term loans and revolving working capital facility loans bear a floating interest rate at the borrower's option based on either LIBOR or base rate, plus a margin, and the margins increase over time.

Obligations under the term loans and revolving working capital facility are secured by substantially all of the assets of the borrower. The outstanding borrowings related to the Channelview credit agreement are non-recourse to Reliant Resources. The Channelview credit agreement contains affirmative and negative covenants, including a negative pledge, that must be met to borrow funds. These covenants are not anticipated to materially restrict Channelview's ability to borrow funds under the credit facility. The Channelview credit agreement allows Channelview 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. Channelview is not expected to satisfy such conditions in 2004. See note 2(l) for a detail of restricted cash under the Channelview credit agreement.

(b) Warrants.

As discussed above in (a), we have outstanding 7,835,894 warrants to acquire shares of our common stock. We determined the fair value of the warrants originally issued of $15 million using a binomial model, created by independent consultants. The value was recorded as a discount to debt and an increase to additional paid-in capital. The debt discount is amortized to interest expense using the effective interest method over the life of the related debt. During 2003, we amortized $7 million to interest expense and the unamortized balance was $8 million as of December 31, 2003.

(c) Interest Rate Derivative Instruments.

Below are our interest rate derivative instruments:

	December 31,					
	2002			2003		
	Notional Amount	Fair Value	Contracts Expire	Notional Amount	Fair Value	Contracts Expire
	(In millions)					
Fixed for floating interest rate swaps(1)	$1,050	$(132)	2003-2010	$ 750	(97)	2005-2010
Interest rate caps(2)	—	—	—	$4,500	4	2004-2005

(1) These interest rate swaps hedge the floating interest rate risk associated with our floating rate long-term debt. These swaps qualify as cash flow hedges under SFAS No. 133 and the periodic settlements are recognized as an adjustment to interest expense in the consolidated statements of operations over the term of the swap agreements. As of December 31, 2002 and 2003, floating rate LIBOR-based interest payments are exchanged for weighted fixed rate interest payments of 6.97% and 6.88%, respectively. As of December 31, 2002 and 2003, these swaps have negative termination values (i.e., we would have to pay). See note 7 for information regarding our derivative financial instruments.

(2) The LIBOR interest rates are capped at a weighted average rate of 3.18% for $3.0 billion in 2004 and 4.35% for $1.5 billion in 2005.

In connection with the Orion Power acquisition, the existing interest rate swaps for the Orion MidWest credit agreement and the Orion NY credit agreement were bifurcated into a debt component and a derivative component. The fair values of the debt components, approximately $59 million for the Orion MidWest credit agreement and $31 million for the Orion NY credit agreement, were based on our incremental borrowing rates at the acquisition date for similar types of borrowing arrangements. The value of the debt component is amortized to interest expense as interest rate swap payments are made. See note 7 for information regarding our derivative financial instruments.

During January 2003, we purchased three-month LIBOR interest rate caps for $29 million to hedge our floating rate risk associated with Reliant Resources' credit facilities. During the first quarter of 2003, these interest rate caps qualified as cash flow hedges of LIBOR-based anticipated borrowings; changes in fair market value during this period were recorded to other comprehensive income (loss) and ineffectiveness was recorded to interest expense. Hedge ineffectiveness during the first quarter of 2003 resulted in the recording of $2 million in interest expense on these interest rate caps. Effective March 31, 2003, these interest rate caps were no longer designated as cash flow hedges, accordingly, subsequent changes in the fair market value are being recorded to net income (loss). The unrealized net loss on these derivative instruments of $15 million (pre-tax) through December 31, 2003 previously reported in other comprehensive loss will be reclassified into earnings during the periods in which the originally designated hedged transactions occur. Subsequent to March 31, 2003, we recorded $9 million in interest expense due to unrealized losses in fair value of the interest rate caps.

In January 2002, we entered into forward-starting interest rate swaps having an aggregate notional amount of $1.0 billion to hedge the interest rate on a portion of then expected future offerings of long-term fixed-rate notes. In 2002, we liquidated these forward-starting interest rate swaps. The liquidation of these swaps resulted in a loss of $55 million, which was recorded in accumulated other comprehensive loss and is being amortized into interest expense in the same periods during which the forecasted interest payment affects earnings, which is through 2012. At December 31, 2002 and 2003, the unamortized balance of such loss was $38 million (pre-tax).

(10) Stockholders' Equity

(a) Initial Public Offering and Common Stock Activity.

In May 2001, Reliant Resources offered 59.8 million shares of its common stock to the public at an IPO price of $30 per share and received net proceeds from the IPO of $1.7 billion. Pursuant to the terms of the master separation agreement with CenterPoint, we used $147 million of the net proceeds to repay certain indebtedness owed to CenterPoint. We used the remainder of the net proceeds of our IPO for repayment of third party borrowings, capital expenditures, repurchases of our common stock and payment of taxes, interest and other payables.

The following table describes our common stock activity for the indicated periods:

	Year Ended December 31,		
	2001	2002	2003
	(shares in thousands)		
Shares of common stock outstanding, net of treasury stock, beginning of period	240,000	288,804	290,605
Shares issued in IPO	59,800	—	—
Shares of treasury stock purchased	(11,000)	—	—
Shares issued to employees under our employee stock purchase plan	—	1,327	2,711
Shares issued to our savings plan	—	309	726
Shares issued under our long-term incentive plans	4	165	550
Shares of common stock outstanding, net of treasury stock, end of period	288,804	290,605	294,592

(b) Treasury Stock Purchases.

During 2001, we purchased 11 million shares of our common stock at an average price of $17.22 per share, or an aggregate purchase price of $189 million. The 11 million shares in treasury stock purchases increased CenterPoint's percentage ownership in us from approximately 80% to approximately 83%. CenterPoint recorded the acquisition of treasury shares under the purchase method of accounting and pushed down the effect to us. As such, we recorded a decrease in net assets from discontinued operations of $43 million and a decrease in additional paid-in capital of $43 million.

Based on our March 2003 credit facilities and our senior secured notes, our ability to purchase treasury stock is restricted; see note 9(a).

(c) Treasury Stock Issuances and Transfers.

The following table describes the changes in the number of shares of our treasury stock for the indicated periods:

	Year Ended December 31,		
	2001	2002	2003
	(shares in thousands)		
Shares of treasury stock, beginning of period	—	11,000	9,199
Shares of treasury stock purchased	11,000	—	—
Shares of treasury stock issued to employees under our employee stock purchase plan	—	(1,327)	(2,711)

	Year Ended December 31,		
	2001	2002	2003
	(shares in thousands)		
Shares of treasury stock issued to our savings plan	—	(309)	(726)
Shares of treasury stock issued under our long-term incentive plans	—	(165)	(550)
Shares of treasury stock, end of period	11,000	9,199	5,212

(11) Earnings Per Share

The following table presents our basic and diluted weighted average shares outstanding:

	Year Ended December 31,		
	2001	2002	2003
	(shares in thousands)		
Diluted Weighted Average Shares Calculation:			
Weighted average shares outstanding	277,144	289,953	293,655
Plus: Incremental shares from assumed conversions:			
Stock options	2	274	—
Restricted stock and performance-based shares	244	1,121	—
Employee stock purchase plan	83	132	—
5.00% convertible senior subordinated notes	—	—	—
Warrants	—	—	—
Weighted average shares assuming dilution	277,473	291,480	293,655

For 2001 and 2002, the computation of diluted EPS excludes purchase options for 8,258,098 and 15,875,183 shares of common stock that have an exercise price (ranging from $23.20 to $34.03 per share and ranging from $8.50 to $34.03 per share, respectively) greater than or equal to the average market price ($22.11 per share and $8.15 per share, respectively) for the respective periods and would thus be anti-dilutive if exercised.

For 2003, as we incurred a loss from continuing operations, we do not assume any potentially dilutive shares in the computation of diluted EPS. The computation of diluted EPS excludes incremental shares in the following amounts from assumed conversions for 2003 (shares in thousands):

Stock options	680(1)
Restricted stock and performance-based shares	1,174
Employee stock purchase plan	151
5.00% convertible senior subordinated notes	14,870(2)
Warrants	364

(1) For 2003, the incremental shares from assumed conversions exclude purchase options for 17,076,778 shares of common stock that have an exercise price (ranging from $5.28 to $34.03 per share) greater than or equal to the average market price ($5.16 per share) and would thus be anti-dilutive if exercised.

(2) If we had recorded income from continuing operations for 2003, for purposes of calculating diluted EPS, we would have increased our income from continuing operations by $5 million for 2003 as it relates to the assumed conversions for our convertible senior subordinated notes.

(12) Stock-Based Incentive Compensation Plans and Retirement and Other Benefit Plans

(a) Stock-Based Incentive Compensation Plans.

At December 31, 2003, our eligible employees participate in four incentive plans described below.

The Reliant Resources, Inc. 2002 Long-Term Incentive Plan (2002 LTIP) permits us to grant awards (stock options, restricted stock, stock appreciation rights, performance awards and cash awards) to key employees, non-employee directors and other individuals who we expect to become key employees within the following six months. Subject to adjustment as provided in the plan, the aggregate number of shares of our common stock that may be issued may not exceed 17,500,000 shares. We also sponsor the Long-Term Incentive Plan of Reliant Resources, Inc. (2001 LTIP), which was effective January 31, 2001, and was amended to provide that no additional awards would be made under the 2001 LTIP after June 6, 2002. Upon the adoption of the 2002 LTIP, the shares remaining available for grant under the 2001 LTIP, totaling approximately 3.5 million, became available as authorized shares available for grant under the 2002 LTIP. These shares are included in the total of 17,500,000 shares available under the 2002 LTIP. Additionally, any shares forfeited under the 2001 LTIP become available for grant under the 2002 LTIP.

The Reliant Resources, Inc. 2002 Stock Plan (2002 Stock Plan) permits us to grant awards (stock options, restricted stock, stock appreciation rights, performance awards and cash awards) to all of our employees (excluding officers subject to Section 16 of the Securities Exchange Act of 1934). The board of directors authorized 6,000,000 shares for grant upon adoption of the 2002 Stock Plan. To the extent these 6,000,000 shares were not granted in 2002, the excess shares were canceled. An additional 6,000,000 shares were authorized for the 2003 plan year. The total number of shares is adjusted for new grants, exercises, forfeitures, cancellations and terminations of outstanding awards under the plan throughout the year. We do not plan to authorize additional shares for this plan after the end of the 2003 plan year.

Prior to the IPO, eligible employees participated in a CenterPoint Long-Term Incentive Compensation Plan and other incentive compensation plans (collectively, the CenterPoint Plans) that provided for the issuance of stock-based incentives including performance-based shares, restricted shares, stock options and stock appreciation rights, to key employees including officers. The Reliant Resources, Inc. Transition Stock Plan was adopted to govern the outstanding restricted shares and options of CenterPoint common stock held by our employees prior to the Distribution date, under the CenterPoint Plans. There were 9,100,000 shares authorized under the Reliant Resources, Inc. Transition Stock Plan and it is anticipated that no additional shares will be issued.

In addition, in conjunction with the Distribution, we entered into an employee matters agreement with CenterPoint. This agreement covered the treatment of outstanding CenterPoint equity awards (including performance-based shares, restricted shares and stock options) under the CenterPoint Plans held by our employees and CenterPoint employees. According to the agreement, each CenterPoint equity award granted to our employees and CenterPoint employees prior to the agreed upon date of May 4, 2001, that was outstanding under the CenterPoint Plans as of the Distribution date, was adjusted. This adjustment resulted in each individual, who was a holder of a CenterPoint equity award, receiving an adjusted equity award of our common stock and CenterPoint common stock, immediately after the Distribution. The combined intrinsic value of the adjusted CenterPoint equity awards and our equity awards, immediately after the record date of the Distribution, was equal to the intrinsic value of the CenterPoint equity awards immediately before the record date of the Distribution.

Performance-based Shares and Restricted Shares. Performance-based shares and restricted shares have been granted to employees without cost to the participants. The performance-based shares generally vest three years after the grant date based upon performance objectives over a three-year cycle, except as discussed below. The restricted shares vest to the participants at various times ranging from immediate vesting to vesting at the end of a five-year period. During 2001, 2002 and 2003, we recorded compensation

expense of $8 million, $4 million and $11 million, respectively, related to performance-based and restricted share grants.

Prior to the Distribution, our employees and CenterPoint employees held outstanding performance-based shares and restricted shares of CenterPoint's common stock under the CenterPoint Plans. On the Distribution date, each performance-based share of CenterPoint common stock outstanding under the CenterPoint Plans, for the performance cycle ending December 31, 2002, was converted to restricted shares of CenterPoint's common stock based on a conversion ratio provided under the employee matters agreement. Immediately following this conversion, outstanding restricted shares of CenterPoint common stock were converted to restricted shares of our common stock, which shares were subject to their original vesting schedule under the CenterPoint Plans. The conversion ratio was determined using the intrinsic value approach described above. As such, our employees and CenterPoint's employees held 302,306 and 87,875 restricted shares, respectively, outstanding under CenterPoint Plans which were converted to 238,457 and 69,334 restricted shares, respectively, of our common stock, of which a majority vested on December 31, 2002.

The following table summarizes Reliant Resources' performance-based shares and restricted shares grant activity for 2001, 2002 and 2003:

	Performance-based Shares	Restricted Shares
Outstanding at December 31, 2000	—	—
Granted	693,135	156,674
Outstanding at December 31, 2001	693,135	156,674
Granted	754,182	671,803
Shares relating to conversion of CenterPoint's restricted shares at Distribution	—	307,791
Released to participants	—	(253,071)
Canceled	(361,785)	(127,930)
Outstanding at December 31, 2002	1,085,532	755,267
Granted	—	3,156,103
Released to participants	(263,501)	(440,578)
Canceled	(330,714)	(467,904)
Outstanding at December 31, 2003	491,317	3,002,888
Weighted average grant date fair value of shares granted for 2001	$ 30.00	$ 33.11
Weighted average grant date fair value of shares granted for 2002	$ 10.59	$ 9.26
Weighted average grant date fair value of shares granted for 2003	$ —	$ 3.93

Stock Options. Under both CenterPoint's and our plans, stock options generally vest over a three-year period and expire after ten years from the date of grant. The exercise price is equal to or greater than the market value of the applicable common stock on the grant date.

As of the record date of the Distribution, CenterPoint converted all outstanding CenterPoint stock options granted prior to May 4, 2001 (totaling 7,761,960 stock options) to a combination of CenterPoint stock options totaling 7,761,960 stock options at a weighted average exercise price of $17.84 and Reliant Resources stock options totaling 6,121,105 stock options with a weighted average exercise price of $8.59. The conversion ratio was determined using an intrinsic value approach as described above.

The following table summarizes Reliant Resources stock option activity for 2001, 2002 and 2003:

	Options	Weighted Average Exercise Price
Outstanding at December 31, 2000	—	—
Granted	8,826,432	$29.82
Canceled	(245,830)	28.28
Outstanding at December 31, 2001	8,580,602	29.86
Granted	7,141,267	10.57
Options relating to conversion of CenterPoint's stock options at Distribution	6,121,105	8.59
Canceled	(2,674,238)	22.25
Outstanding at December 31, 2002	19,168,736	16.99
Granted	4,726,797	3.83
Canceled	(2,012,376)	18.44
Exercised	(333)	4.95
Outstanding at December 31, 2003	21,882,824	13.98
Options exercisable at December 31, 2001	6,500	$30.00
Options exercisable at December 31, 2002	8,232,294	$16.16
Options exercisable at December 31, 2003	14,722,136	$15.47

The following table summarizes, with respect to Reliant Resources, the range of exercise prices and the weighted average remaining contractual life of the options outstanding and the range of exercise prices for the options exercisable at December 31, 2003:

	Options Outstanding			Options Exercisable	
	Options Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Outstanding	Weighted Average Exercise Price
Ranges of Exercise Prices					
Exercisable at:					
$2.44 — $10.00	9,982,718	$ 6.04	6.0	6,423,643	$ 7.23
$10.01 — $20.00	5,900,887	11.17	6.0	3,602,374	11.29
$20.01 — $34.03	5,999,219	29.96	5.4	4,696,119	29.96
Total	21,882,824	13.98	5.8	14,722,136	15.47

Of the outstanding and exercisable stock options as of December 31, 2003, 20,135,837 and 13,028,449, respectively, relate to our current or former employees. The remainder of outstanding and exercisable stock options as of December 31, 2003, primarily relate to employees of CenterPoint.

Employee Stock Purchase Plan. In the second quarter of 2001, we established the Reliant Resources, Inc. Employee Stock Purchase Plan (ESPP) under which we are authorized to sell up to 18,000,000 shares of our common stock to our employees. Under the ESPP, employees may contribute up to 15% of their compensation, as defined, towards the purchase of shares of our common stock at a price of 85% of the lower of the market value at the beginning or end of each six-month offering period. The

initial purchase period began on the date of the IPO and ended December 31, 2001. The market value of the shares acquired in any year may not exceed $25,000 per individual. Amounts contributed in excess of $21,250 during a purchase period will be refunded to the employee. The following table details the number of shares (and price per share) issued under our ESPP for 2002 and 2003 and through January 2004:

	Shares	Price/Share
January 2002	550,781	$14.07
July 2002	776,062	7.44
January 2003	717,931	2.66
July 2003	1,992,845	2.82
January 2004	763,402	5.27

Pro Forma Effect on Net Income (Loss). In accordance with SFAS No. 123, we apply the intrinsic value method contained in APB No. 25 and disclose the required pro forma effect on net income (loss) and earnings (loss) per share as if the fair value method of accounting for stock compensation was used. The weighted average grant date fair value for an option to purchase our common stock granted during 2001, 2002 and 2003 was $13.35, $5.09 and $3.10, respectively. The weighted average grant date fair value of a purchase right issued under our ESPP during 2001, 2002 and 2003 was $9.24, $4.51 and $1.80, respectively. The weighted average grant date fair value for an option to purchase CenterPoint common stock granted during 2001 was $9.25. The fair values were estimated using the Black-Scholes option valuation model with the following weighted average assumptions:

	Reliant Resources Stock Options		
	2001	2002	2003
Expected life in years	5	5	5
Risk-free interest rate	4.94%	4.43%	2.75%
Estimated volatility	42.65%	46.99%	113.64%
Expected common stock dividend	0%	0%	0%

	Reliant Resources Purchase Rights under ESPP		
	2001	2002	2003
Expected life in months	8	6	6
Risk-free interest rate	3.92%	1.89%	1.18%
Estimated volatility	46.48%	71.32%	110.73%
Expected common stock dividend	0%	0%	0%

	CenterPoint Stock Options 2001
Expected life in years	5
Risk-free interest rate	4.87%
Estimated volatility of CenterPoint common stock	31.91%
Expected common stock dividend	5.75%

For 2001 and 2002, we determined stock option expected volatility based on an average of the historical volatility of our common stock and a group of companies we consider similar to us. For 2003, we determined stock option expected volatility based on the historical volatility of our common stock. The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options, which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because our

employee stock options and purchase rights have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in our opinion, the existing models do not necessarily provide a single measure of the fair value of our employee stock options and purchase rights.

For the pro forma computation of net income (loss) and earnings (loss) per share as if the fair value method of accounting had been applied to all stock awards, see note 2(h).

(b) Pension.

We sponsor multiple noncontributory defined benefit pension plans covering certain union and non-union employees. Depending on the plan, the benefit payment is either based on years of service with final average salary and covered compensation, or in the form of a cash balance account which grows based on a percentage of annual compensation and accrued interest.

Prior to March 1, 2001, we participated in CenterPoint's noncontributory cash balance pension plan. Effective March 1, 2001, we no longer accrued benefits under this noncontributory pension plan for our domestic non-union employees (Resources Participants). Effective March 1, 2001, each Resources Participant's unvested pension account balance became fully vested and a one-time benefit enhancement was provided to some qualifying participants. During the first quarter of 2001, we incurred a charge to earnings of $83 million (pre-tax) for a one-time benefit enhancement and a gain of $23 million (pre-tax) related to the curtailment of CenterPoint's pension plan. In connection with the Distribution, we incurred a loss of $65 million (pre-tax) related to the accounting settlement of the pension obligation. In connection with recording the accounting settlement, CenterPoint contributed certain benefit plan deferred losses, net of taxes, totaling $18 million that were deemed to be associated with our benefit obligation. Upon the Distribution, we effectively transferred to CenterPoint our pension obligation. After the Distribution, each Resources Participant may elect to have his accrued benefit (a) left in the CenterPoint pension plan for which CenterPoint is the plan sponsor, (b) rolled over to our savings plan or an individual retirement account or (c) paid in a lump-sum or annuity distribution.

Our funding policy is to review amounts annually in accordance with applicable regulations in order to determine contributions necessary to achieve adequate funding of projected benefit obligations. We use a December 31 measurement date for our plans. Our pension obligation and funded status are as follows:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$137.6	$ 72.5
Service cost	6.4	8.1
Interest cost	10.1	4.9
Curtailments and benefits enhancement	0.6	—
Settlement loss	—	0.8
Transfers to affiliates	(125.7)	—
Acquisitions	39.8	—
Benefits paid	(6.2)	(3.2)
Plan amendments	2.0	0.7
Actuarial loss	7.9	7.1
Benefit obligation, end of year	$ 72.5	$ 90.9
Change in Plan Assets		
Fair value of plan assets, beginning of year	$152.8	$ 29.5
Transfers/allocations to affiliates	(147.0)	—
Employer contributions	7.8	12.4
Benefits paid	(6.2)	(3.2)
Acquisitions	20.9	—
Actual investment return	1.2	7.1
Fair value of plan assets, end of year	$ 29.5	$ 45.8
Reconciliation of Funded Status		
Funded status	$(43.0)	$(45.1)
Unrecognized prior service cost	2.0	2.4
Unrecognized actuarial loss	18.2	20.2
Net amount recognized, end of year	$(22.8)	$(22.5)

Amounts recognized in the consolidated balance sheets are as follows:

	December 31,	
	2002	2003
	(In millions)	
Accrued benefit cost	$(24.6)	$(23.0)
Intangible assets	0.8	0.5
Accumulated other comprehensive loss	1.0	—
Net amount recognized	$(22.8)	$(22.5)

The accumulated benefit obligation for all defined benefit plans was $50 million and $61 million at December 31, 2002 and 2003, respectively.

Net pension cost includes the following components:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Service cost — benefits earned during the period	$ 3.5	$ 6.4	$ 8.1
Interest cost on projected benefit obligation	8.2	10.1	4.9
Expected return on plan assets	(11.9)	(12.9)	(2.7)
Curtailment and benefits enhancements	44.9	0.6	—
Accounting settlement charge	—	64.9	0.6
Net amortization	0.6	0.1	1.1
Net pension cost	$ 45.3	$ 69.2	$12.0

The significant weighted average assumptions used to determine the pension benefit obligation include the following:

	December 31,	
	2002	2003
Discount rate	6.75%	6.25%
Rate of increase in compensation levels	4.0-4.5%	4.5%

The significant weighted average assumptions used to determine the net pension cost include the following:

	Year Ended December 31,		
	2001	2002	2003
Discount rate	7.5%	7.25%	6.75%
Rate of increase in compensation levels	3.5-5.5%	3.5-5.5%	4.0-4.5%
Expected long-term rate of return on assets	10.0%	8.5-9.5%	8.5%

As of December 31, 2003, our expected long-term rate of return on pension plan assets is developed based on third party models. These models consider expected inflation, current dividend yields, expected corporate earnings growth and risk premiums based on the expected volatility of each asset category. The expected long-term rates of return for each asset category are weighted to determine our overall expected long-term rate of return on pension plan assets. In addition, peer data and historical returns are reviewed.

Our pension plan weighted average asset allocations at December 31, 2002 and 2003 and target allocation for 2004 by asset category are as follows:

	Percentage of Plan Assets at December 31,		Target Allocation
	2002	2003	2004
Domestic equity securities	55%	55%	55%
International equity securities	15	15	15
Debt securities	30	30	30
Total	100%	100%	100%

In managing the investments associated with the pension plans, our objective is to exceed, on a net-of-fee basis, the rate of return of a performance benchmark composed of the following indices:

Asset Class	Index	Weight
Domestic equity securities	Wilshire 5000 Index	55%
International equity securities	MSCI All Country World Ex-U.S. Index	15
Debt securities	Lehman Brothers Aggregate Bond Index	30
Total		100%

As a secondary measure, asset performance is compared to the returns of a universe of comparable funds, where applicable, over a full market cycle.

During 2001, 2002 and 2003, we made cash contributions of $1 million, $8 million and $12 million, respectively, to our pension plans. We expect cash contributions to approximate $15 million during 2004.

Information for pension plans with an accumulated benefit obligation in excess of plan assets is as follows:

	December 31,	
	2002	2003
	(In millions)	
Projected benefit obligation	$70.9	$90.9
Accumulated benefit obligation	48.7	60.7
Fair value of plan assets	28.0	45.8

Prior to the Distribution, we participated in CenterPoint's non-qualified pension plan which allowed participants to retain the benefits to which they would have been entitled under CenterPoint's qualified noncontributory pension plan except for the federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. Effective March 1, 2001, we no longer provide future non-qualified pension benefits to our employees. In connection with the Distribution, we assumed CenterPoint's obligation related to our employees under the non-qualified pension plan. The expense associated with this non-qualified plan was $2 million, $3 million and $6 million in 2001, 2002 and 2003, respectively. During 2003, we recognized an accounting settlement charge of $5 million (pre-tax) related to participants in our non-qualified pension plan rolling over to a non-qualified deferred compensation plan established in 2002, as further discussed below. We believe it was appropriate to discontinue the application of pension accounting to these benefits. After the Distribution, participants in the non-qualified pension plan were given the opportunity to elect to receive distributions or have their account balance funded into a rabbi trust. Accordingly, $17 million of the non-qualified pension plan account balances was transferred to the rabbi trust, as discussed below. The accrued benefit liability for the non-qualified pension plan was $5 million and $6 million as of December 31, 2002 and 2003, respectively (excluding the liability related to participants rolling over to a non-qualified deferred compensation plan). In addition, the accrued benefit liabilities as of December 31, 2002 and 2003 include the recognition of minimum liability adjustments of $7 million and $2 million, respectively, which is reported as a component of other comprehensive income (loss), net of income tax effects.

(c) Savings Plan.

We have employee savings plans that are tax-qualified plans under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and include a cash or deferred arrangement under Section 401(k) of the Code for substantially all our employees. Prior to February 1, 2002, our non-union employees, except for REMA non-union employees and our foreign subsidiaries' employees, participated in

CenterPoint's employee savings plan that is a tax qualified plan under Section 401(a) of the Code, and included a cash or deferred arrangement under Section 401(k) of the Code.

Under the plans, participating employees may contribute a portion of their compensation, pre-tax or after-tax, generally up to a maximum of 16% of compensation with the exception of the Orion Power savings plan under which contributions are generally up to a maximum of 18% of compensation. Our savings plans matching contribution and any payroll period discretionary employer contribution will be made in cash; any discretionary annual employer contribution, as applicable, may be made in our common stock, cash or both.

Our savings plans benefit expense was $20 million, $24 million and $29 million in 2001, 2002 and 2003, respectively.

(d) Postretirement Benefits.

Effective March 1, 2001, we discontinued providing subsidized postretirement benefits to our domestic non-union employees. We incurred a pre-tax loss of $40 million in the first quarter of 2001 related to the curtailment of our postretirement obligation. In connection with the Distribution, we incurred a pre-tax gain of $18 million related to the accounting settlement of postretirement benefit obligations. Prior to March 1, 2001, through a CenterPoint subsidized postretirement plan, we provided some postretirement benefits for substantially all of our retired employees. We continue to provide subsidized postretirement benefits to certain union employees and Orion Power employees. We fund our postretirement benefits on a pay-as-you-go basis. We use a December 31 measurement date for our plans.

Accumulated postretirement benefit obligation and funded status are as follows:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 28.0	$ 58.3
Service cost	3.8	3.1
Interest cost	3.7	3.9
Benefit payments	—	(0.6)
Participant contributions	—	0.1
Acquisitions	31.0	—
Plan amendments	9.5	—
Accounting settlement gain	(22.2)	—
Actuarial loss	4.5	7.9
Benefit obligation, end of year	$ 58.3	$ 72.7
Change in Plan Assets		
Fair value of plan assets, beginning of year	$ —	$ —
Employer contributions	—	0.5
Participant contributions	—	0.1
Benefits paid	—	(0.6)
Fair value of plan assets, end of year	$ —	$ —
Reconciliation of Funded Status		
Funded status	$(58.3)	$(72.7)
Unrecognized prior service cost	9.5	8.5
Unrecognized actuarial loss	5.1	12.6
Net amount recognized, end of year	$(43.7)	$(51.6)

Amounts recognized in the consolidated balance sheets are as follows:

	December 31,	
	2002	2003
	(In millions)	
Accrued benefit cost	$(43.7)	$(51.6)

Net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Service cost — benefits earned during the period	$ 1.6	$ 3.8	$3.1
Interest cost on projected benefit obligation	1.3	3.7	3.9
Curtailment charge	39.5	—	—
Accounting settlement gain	—	(17.6)	—
Net amortization	0.1	0.3	1.4
Net postretirement benefit cost (benefit)	$42.5	$ (9.8)	$8.4

The significant weighted average assumptions used to determine the accumulated postretirement benefit obligation include the following:

	December 31,	
	2002	2003
Discount rate	6.75%	6.25%
Rate of increase in compensation levels	4.5%	4.5%

The significant weighted average assumptions used to determine the net postretirement benefit cost include the following:

	Year Ended December 31,		
	2001	2002	2003
Discount rate	7.5%	7.25%	6.75%
Rate of increase in compensation levels	2.0%	2.0-4.5%	4.5%

The following table shows our assumed health care cost trend rates used to measure the expected cost of benefits covered by our postretirement plan:

	Year Ended December 31,		
	2001	2002	2003
Health care cost trend rate assumed for next year	12.0%	11.25%	10.5%
Rate to which the cost trend rate is assumed to gradually decline	5.5%	5.5%	5.5%
Year that the rate reaches the rate to which it is assumed to decline	2011	2011	2011

Assumed health care cost trend rates have a significant effect on the amounts reported for our health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects as of December 31, 2003:

	One-Percentage Point	
	Increase	Decrease
	(In millions)	
Effect on service and interest cost	$ 1	$ (1)
Effect on accumulated postretirement benefit obligation	13	(11)

During 2002, the retiree medical benefits for certain union employees were redesigned to allow for a company-provided subsidy for premium coverage attributable to qualifying employees. This resulted in a $10 million increase in the accumulated postretirement benefit obligation during 2002.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 became law. This law introduces a prescription drug benefit, as well as a federal subsidy under certain circumstances to sponsors of retiree health care benefit plans. In January 2004, the FASB issued FASB Staff Position No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." This FASB staff position permits sponsors of postretirement health care plans that provide a prescription drug benefit to make a one time election to defer accounting for the effects of this law until the earlier of: (a) the issuance of authoritative guidance on accounting for the federal subsidy or (b) the occurrence of a significant event that would call for remeasurement of a plan's assets and obligations, such as a plan amendment, settlement or curtailment. We have elected to defer accounting for the effects of this law. The measurements of our accumulated postretirement benefit obligation and net periodic postretirement benefit cost do not reflect the effect of this law. When authoritative guidance on accounting for the federal subsidy is issued, we will revise our accounting as required.

(e) Postemployment Benefits.

We record postemployment benefits based on SFAS No. 112, "Employer's Accounting for Postemployment Benefits," which requires the recognition of a liability for benefits provided to former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily health care and life insurance benefits for participants in the long-term disability plan). Net postemployment benefit costs were insignificant for 2001 and 2002 and $3 million for 2003.

(f) Other Non-qualified Plans.

Effective January 1, 2002, key and highly compensated employees are eligible to participate in our non-qualified deferred compensation and savings restoration plan. The plan allows eligible employees to elect to defer up to 80% of their annual base salary and/or up to 100% of their eligible annual bonus. In addition, the plan allows participants to retain the benefits which they would have been entitled to under our qualified savings plans, except for the federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. We fund these deferred compensation and savings restoration liabilities by making contributions to a rabbi trust. Plan participants direct the allocation of their deferrals and restoration benefits between one or more of our designated investment funds within the rabbi trust.

Through 2001, certain eligible employees participated in CenterPoint's deferred compensation plans, which permit participants to elect each year to defer a percentage of that year's salary and up to 100% of that year's annual bonus. Interest generally accrued on deferrals made in 1989 and subsequent years at a rate equal to the average Moody's Long-Term Corporate Bond Index plus 2%, determined annually until termination when the rate is fixed at the greater of the rate in effect at age 64 or at age 65. Fixed rates of 19% to 24% were established for deferrals made in 1985 through 1988. We recorded interest expense related to these deferred compensation obligations of $4 million, $2 million and $1 million in 2001, 2002 and 2003, respectively. Each of our employees that participated in this plan has elected to have his CenterPoint non-qualified deferred compensation plan account balance, after the Distribution: (a) paid in a lump-sum distribution, (b) placed in a new deferred compensation plan established by us, which generally mirrors the former CenterPoint deferred compensation plans, or (c) rolled over to our deferred compensation and savings restoration plan discussed above.

Our discounted deferred compensation obligation related to the deferred compensation obligation under the plan that mirrors the CenterPoint deferred compensation plan was $12 million as of December 31, 2002 and 2003. Our deferred compensation and savings restoration liability related to the deferred compensation and savings restoration plan established effective January 1, 2002 (discussed above)

was $23 million and $28 million and the related investment in the rabbi trust was $23 million and $28 million as of December 31, 2002 and 2003, respectively.

(g) Other Employee Matters.

As of December 31, 2003, approximately 27% of our employees are subject to collective bargaining arrangements, of which contracts covering 7% of our employees will expire prior to December 31, 2004.

(13) Income Taxes

The components of income (loss) from continuing operations before income taxes are as follows:

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
United States	$779.1	$233.7	$(812.6)
Foreign	(27.6)	(4.4)	(9.5)
Income (loss) from continuing operations before income taxes	$751.5	$229.3	$(822.1)

Our current and deferred components of income tax expense (benefit) were as follows:

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Current			
Federal	$254.5	$(59.7)	$ (14.3)
State	3.8	31.5	34.4
Foreign	(2.7)	0.2	0.2
Total current	255.6	(28.0)	20.3
Deferred			
Federal	23.7	140.7	90.0
State	15.6	(7.1)	(30.2)
Foreign	(4.0)	0.4	—
Total deferred	35.3	134.0	59.8
Income tax expense	$290.9	$106.0	$ 80.1

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

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Income (loss) from continuing operations before income taxes	$751.5	$229.3	$(822.1)
Federal statutory rate	35%	35%	35%
Income tax expense (benefit) at statutory rate	263.0	80.3	(287.7)
Net addition (reduction) in taxes resulting from:			
Wholesale energy goodwill impairment	—	—	344.8
State income taxes, net of valuation allowances and federal income tax benefit	12.6	15.9	2.8
Goodwill amortization	8.6	—	—
Federal and foreign valuation allowances	—	11.6	3.3
Commodity Futures Trading Commission settlement	—	—	6.3
Other, net	6.7	(1.8)	10.6
Total	27.9	25.7	367.8
Income tax expense	$290.9	$106.0	$ 80.1
Effective rate	38.7%	46.2%	NM(1)

(1) Not meaningful as we had a pre-tax loss of $822 million and income tax expense of $80 million. The primary reason is due to the wholesale energy segment's goodwill impairment of $985 million, for which no tax benefit can be recognized as the goodwill is non-deductible.

Following were our tax effects of temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their respective tax bases:

	As of December 31,	
	2002	2003
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts and credit provisions	$ 30.7	$ 29.8
Contractual rights and obligations	13.7	—
Adjustment to fair value for debt	10.9	8.6
Operating loss carryforwards	66.8	—
Accrual for payment to CenterPoint Energy, Inc.	—	66.9
Other	7.5	12.4
Total current deferred tax assets	129.6	117.7
Non-current:		
Employee benefits	51.5	61.9
Operating loss carryforwards	55.2	293.7
Environmental reserves	21.5	15.1
Trading and derivative liabilities, net	—	10.0
Foreign exchange gains	11.6	5.5
Accrual for payment to CenterPoint Energy, Inc.	48.7	—
Adjustment to fair value for debt	49.9	38.2
Contractual rights and obligations	—	0.8
Equity method investments	9.6	6.0
Other	31.1	32.2
Valuation allowance	(48.3)	(263.1)
Total non-current deferred tax assets	230.8	200.3
Total deferred tax assets	$ 360.4	$ 318.0
Deferred tax liabilities:		
Current:		
Trading and derivative assets, net	$ 61.7	$ 18.7
Hedges of net investment in foreign subsidiaries	20.6	—
Other	7.3	2.5
Total current deferred tax liabilities	89.6	21.2

	As of December 31,	
	2002	2003
	(In millions)	
Non-current:		
Depreciation and amortization	583.5	699.0
Trading and derivative assets, net	1.3	—
Contractual rights and obligations	10.3	—
Other	25.8	19.9
Total non-current deferred tax liabilities	620.9	718.9
Total deferred tax liabilities	$ 710.5	$ 740.1
Accumulated deferred income taxes, net	$(350.1)	$(422.1)

Tax Attribute Carryovers. At December 31, 2003, we had approximately $797 million, $41 million and $570 million of state and foreign net operating loss carryforwards and capital loss carryforwards, respectively. As of December 31, 2003, we did not have any federal net operating loss carryforwards. The state loss carryforwards, foreign loss carryforwards and capital loss carryforwards can be carried forward to offset future income or capital gains, as applicable, through the years 2023, 2010 and 2008, respectively.

Subsequent to the Distribution, we ceased being a member of the CenterPoint consolidated tax group. This separation could have future income tax implications for us. Our separation from the CenterPoint consolidated tax group changed our overall future income tax posture. As a result, we could be limited in our future ability to effectively use future tax attributes. We agreed with CenterPoint that we may carry back net operating losses we generate in our tax years after deconsolidation to tax years when we were part of the CenterPoint consolidated tax group subject to CenterPoint's consent and any existing statutory carryback limitations. CenterPoint agreed not to unreasonably withhold such consent. In accordance with this agreement, in 2003, we carried back net operating losses related to the fourth quarter of 2002 to CenterPoint's pre-Distribution tax years and received a $76 million tax refund in January 2004. In addition, in February 2004, we received $9 million from CenterPoint in settlement of certain tax matters pursuant to such agreement.

The valuation allowance reflects a $46 million net increase in 2002 and a $215 million net increase in 2003. The net increase in 2002 results primarily from increased state net operating losses and impairments on capital assets. In addition, in connection with the Orion Power acquisition, we recorded a valuation allowance of $30 million in 2002 due to state net operating losses. The net increase in 2003 results primarily from (a) increased state net operating losses in jurisdictions where we do not expect to receive a future tax benefit and (b) a capital loss on the sale of our European energy operations. These net changes for 2002 and 2003 also resulted from a reassessment of our future ability to use federal, state and foreign tax net operating loss and capital loss carryforwards.

(14) Commitments

(a) Lease Commitments.

REMA Sale-leasebacks. In 2000, we entered into separate sale-leaseback transactions with each of three owner-lessors' respective 16.45%, 16.67% and 100% interests in the Conemaugh, Keystone and Shawville generating facilities, respectively, acquired in the REMA acquisition during 2000. As lessee, we lease an interest in each facility from each owner-lessor under a facility lease agreement. We expect to make lease payments through 2029 under these leases, with total cash payments of $1.3 billion remaining as of December 31, 2003. The lease terms expire in 2026 (Shawville facility) and 2034 (Conemaugh and Keystone facilities). The equity interests in all the subsidiaries of REMA are pledged as collateral for

REMA's lease obligations and the subsidiaries have guaranteed the lease obligations. Additionally, REMA is obligated to provide credit support for its lease obligations. See note 9(a) for discussion. These lease obligations, which were entered into in connection with a financing transaction, are non-recourse to Reliant Resources. During 2001, 2002 and 2003, we made lease payments related to the REMA sale-leasebacks of $259 million, $138 million and $77 million, respectively. As of December 31, 2002 and 2003, we have recorded a prepaid lease obligation related to the REMA sale-leasebacks of $59 million in other current assets and of $200 million and $218 million, respectively, in other long-term assets.

The lease documents contain restrictive covenants that restrict REMA's ability to, among other things, make dividend distributions unless REMA satisfies various conditions. As of December 31, 2003, all of these conditions were met.

Tolling Agreements. In the first quarter of 2001, we entered into tolling arrangements with a third party to purchase the rights to utilize and dispatch electric generating capacity of approximately 1,100 MW extending through 2012. Two gas-fired, simple-cycle peaking plants generate this electricity. We did not pay any amounts under these tolling arrangements during 2001. We paid $45 million and $54 million in tolling payments during 2002 and 2003, respectively. The tolling arrangements qualify as operating leases.

We have a long-term office space lease for our corporate headquarters. The lease term, which commenced in 2003, expires in 2018, subject to two five-year renewal options.

Cash Obligations Under Operating Leases. The following table sets forth information concerning our cash obligations under non-cancelable long-term operating leases as of December 31, 2003. Other non-cancelable, long-term operating leases principally consist of tolling arrangements, as discussed above, rental agreements for building space, including the office space lease discussed above, data processing equipment and vehicles, including major work equipment:

	REMA Sale-Leaseback Obligation	Other	Total
	(In millions)		
2004	$ 84	$ 97	$ 181
2005	75	95	170
2006	64	94	158
2007	65	68	133
2008	62	63	125
2009 and thereafter	997	385	1,382
Total	$1,347	$802	$2,149

Operating Lease Expense. Total lease expense for all operating leases was $72 million, $117 million and $159 million during 2001, 2002 and 2003, respectively.

(b) Construction Agency Agreements with Off-balance Sheet Entities in 2001 and 2002.

In 2001, certain of our subsidiaries entered into operative documents with entities to facilitate the development, construction, financing and leasing of several power generation projects. We did not consolidate the entities as of December 31, 2002. Certain of our subsidiaries acted as construction agents for these entities and were responsible for completing construction of these projects by December 31, 2004. However, we had generally limited our risk during construction to an amount not to exceed 89.9% of costs incurred to date, except in certain events. Upon completion of an individual project and exercise of the lease option, our subsidiaries would have been required to make lease payments in an amount sufficient to

provide a return to the investors. Reliant Resources had guaranteed its subsidiaries' obligations under the operative agreements during the construction periods. As of December 31, 2002, the entities had property, plant and equipment of $1.3 billion, net other assets of $3 million and secured debt obligations of $1.3 billion. As of December 31, 2002, the entities had equity from unaffiliated third parties of $49 million.

Due to the adoption of FIN No. 46 (as explained in note 2(c)), we began to consolidate these entities effective January 1, 2003. The financing agreements, the construction agency agreements and the related guarantees were terminated as part of the refinancing in March 2003. For information regarding the refinancing, see note 9(a).

(c) Off-balance Sheet Equipment Financing Structure in 2001 and 2002.

We, through a subsidiary, entered into an agreement with a bank in 2000 whereby the bank, as owner, entered into contracts for the purchase and construction of power generation equipment and our subsidiary, or its subagent, acted as the bank's agent in connection with administering the contracts for such equipment. The agreement was terminated in September 2002. Our subsidiary, or its designee, had the option at any time to purchase, or, at equipment completion, subject to certain conditions, to lease the equipment or to assist in the remarketing of the equipment under terms specified in the agreement. We were required to cash collateralize our obligation to administer the contracts. This cash collateral was approximately equivalent to the total payments by the bank for the equipment, interest and other fees. As of December 31, 2001, we had deposits of $230 million in the collateral account.

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 collateral deposits were returned to us. In May 2002, we were assigned and exercised a purchase option for a contract for equipment totaling $20 million under which payments and interest during construction totaled $8 million. We used $8 million of our collateral deposits to complete the purchase. After the purchase, we canceled the contract and recorded a $10 million loss on the cancellation of the contract, which included a $2 million termination fee. Immediately prior to the expiration of the agreement in September 2002, we terminated the agreement and were assigned and exercised purchase options for contracts for steam and combustion turbines and two heat recovery steam generators with an aggregate cost of $121 million under which payments and interest during construction totaled $94 million. We used $94 million of our collateral deposits to complete the purchase.

Pursuant to SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), we evaluated for impairment the steam and combustion turbines and two heat recovery steam generators purchased in September 2002. Based on our analysis, we determined this equipment was impaired and accordingly recognized a $37 million pre-tax impairment loss that is recorded as depreciation expense in 2002 in our consolidated statement of operations. The fair value of the equipment and thus the impairments were determined using a combination of quoted market prices and prices for similar assets.

(d) Payment to CenterPoint in 2004.

Consistent with the Texas electric restructuring law, we expect to make a payment to CenterPoint for our residential customers. This provision of the law requires a payment be made to CenterPoint unless, as of December 31, 2003, 40% or more of the electric power consumed in 2000 by each class of customer in the Houston service territory was provided by other retail electric providers. Currently, we estimate the payment to be $175 million and expect that the payment will be made in the fourth quarter of 2004. This amount is computed by multiplying $150 by the number of residential customers that we served on January 1, 2004 in the Houston service territory, less the number of residential customers we served in other areas of Texas on that same date. We recognized $128 million (pre-tax) in the third and fourth

quarters of 2002 and $47 million (pre-tax) in the first quarter of 2003 for a total accrual of $175 million as of December 31, 2003. We recognized the total obligation over the period we recognized the related revenues.

We will not be required to make a similar payment for small commercial customers because in January 2004 the PUCT found that the 40% target for small commercial customers was reached before the end of 2003.

(e) Guarantees.

We have guaranteed, in the event CenterPoint becomes insolvent, certain non-qualified benefits of CenterPoint's and its subsidiaries' existing retirees at the date of Distribution. The estimated maximum potential amount of future payments under this guarantee was approximately $58 million and $57 million as of December 31, 2002 and 2003, respectively. There are no assets held as collateral. There is no liability recorded in our consolidated balance sheet as of December 31, 2003 for this guarantee. We believe the likelihood that we would be required to perform or otherwise incur any significant losses associated with this guarantee is remote.

We have entered into contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchase and sale agreements, commodity purchase and sale agreements, operating agreements, service agreements, lease agreements, procurement agreements and certain debt agreements. In general, these provisions indemnify the counterparty for matters such as breaches of representations and warranties and covenants contained in the contract and/or against certain specified liabilities. In the case of commodity purchase and sale agreements, generally damages are limited through liquidated damages clauses whereby the parties agree to establish damages as the costs of covering any breached performance obligations. In the case of debt agreements, we generally indemnify against liabilities that arise from the preparation, entry into, administration or enforcement of the agreement. Under these indemnifications and guarantees, the maximum potential amount is not estimable given that the magnitude of any claims under the indemnifications would be a function of the extent of damages actually incurred, which is not practicable to estimate unless and until the event occurs. We consider the likelihood of making any material payments under these provisions to be remote.

(f) Other Commitments.

Property, Plant and Equipment Purchase Commitments. As of December 31, 2003, we had two generating facilities under construction. Total estimated cost of constructing these facilities is $1.2 billion. As of December 31, 2003, we had incurred $1.1 billion of the total forecasted project costs.

Fuel Supply, Commodity Transportation, Purchase Power and Electric Capacity Commitments. We are a party to fuel supply contracts, commodity transportation contracts, and purchase power and electric capacity contracts, that have various quantity requirements and durations that are not classified as trading and derivative assets and liabilities and hence are not included in our consolidated balance sheet as of December 31, 2003. Minimum purchase commitment obligations under these agreements are as follows, as of December 31, 2003:

	Fuel Commitments	Transportation Commitments	Purchased Power and Electric Capacity Commitments
		(In millions)	
2004	$250	$ 107	$1,172
2005	192	109	462
2006	129	107	85
2007	54	97	—
2008	14	92	—
2009 and thereafter	139	1,009	—
Total	$778	$1,521	$1,719

Our aggregate electric capacity commitments, including capacity auction products, are for 22,612 MW, 12,276 MW and 5,168 MW for 2004, 2005 and 2006, respectively. Included in the above purchase power and electric capacity commitments are amounts acquired from Texas Genco. For additional discussion of this commitment, see note 4.

As of December 31, 2003, the maximum remaining terms under any individual fuel supply contract, transportation contract and purchased power and electric and gas capacity contract is 16 years, 20 years and three years, respectively.

Sale Commitments. As of December 31, 2003, we have sale commitments, including electric energy and capacity sale contracts, which are not classified as trading and derivative assets and liabilities and hence are not included in our consolidated balance sheet. At execution, the estimated minimum sale commitments under these contracts were $1.9 billion, $751 million, $210 million, $39 million and $2 million in 2004, 2005, 2006, 2007 and 2008, respectively.

In addition, in January 2002, we began providing retail electric services to approximately 1.7 million residential and small commercial customers previously served by CenterPoint's electric utility division. In the Houston area, the Texas electric restructuring law required us, as a former affiliate of the transmission and distribution utility in Houston, to sell electricity to residential or small commercial customers only at a specified price, or "price-to-beat" until the earlier of January 1, 2005, or the date that 40% or more of the electric power consumed by the applicable customer class is served by other retail electric providers. In January 2004, the PUCT made such a determination for small commercial customers and we are now permitted to sell electricity at unregulated prices both outside and in the Houston area for these customers. We do not expect to meet the 40% test for our residential customers in the Houston area. The price-to-beat was the only price that could be offered by us to residential and small commercial customers in the Houston area throughout 2003. The Texas electric restructuring law requires us to continue to make electricity available for our small commercial customers in the Houston area at the price-to-beat until January 1, 2007. The PUCT's regulations allow our retail electric provider to adjust its price-to-beat fuel factor based on a percentage change in the price of natural gas. In addition, the retail electric provider may also request an adjustment as a result of changes in the price of purchased energy. We can request up to two adjustments to our price-to-beat in each year. During 2002 and 2003, we requested and the PUCT approved two such adjustments in each year.

Provider of Last Resort Contracts. One of our subsidiaries is contractually obligated through the end of 2004 to provide energy to Duquesne Light Company to satisfy the demands of any customer in its service area that purchases power from Duquesne Light Company as its "provider of last resort." These contracts do not specify a minimum or maximum quantity of energy to be supplied. Although we expect to produce more energy than needed to meet these contractual obligations, it is possible that, due to seasonal variations in demand or operational outages, our subsidiary may occasionally need to purchase energy from third parties to cover its contractual obligations. Since these events are likely to occur at times of higher market prices, we are at risk that the cost of power purchased may exceed the fixed prices for power under contracts with Duquesne Light Company. Failure to provide sufficient energy under the terms of the contracts could give rise to, in addition to other direct damages, penalties of up to $1,000 per megawatt hour, depending upon the circumstances of such under delivery. During 2002 and 2003, we did not incur or pay any penalties.

Naming Rights to Houston Sports Complex. In October 2000, we acquired the naming rights for a football stadium and other convention and entertainment facilities included in the stadium complex. The agreement extends through 2032. In addition to naming rights, the agreement provides us with significant sponsorship rights. The aggregate cost of the naming rights is approximately $300 million. Starting in 2002, we began to pay $10 million each year, which will continue through 2032, for the annual naming, advertising and other benefits under this agreement.

Long-term Power Generation Maintenance Agreements. We have entered into long-term maintenance agreements that cover certain periodic maintenance, including parts, on power generation turbines. The long-term maintenance agreements terminate over the next 5 to 13 years based on turbine usage. Estimated cash payments over the next five years for these agreements are as follows (in millions):

2004	$ 50
2005	38
2006	36
2007	48
2008	39
Total	$211

Other Commitments. In addition to items discussed in our consolidated financial statements, our other contractual commitments have various quantity requirements and durations and are not considered material either individually or in the aggregate to our results of operations or cash flows.

(15) Contingencies

(a) Legal and Environmental Matters.

We are involved in a number of legal, environmental and other proceedings before courts and governmental agencies. We are also subject to ongoing investigations by various governmental agencies, including investigations into possible criminal law violations. Although we cannot predict the outcome of these proceedings, many of these matters involve substantial claim amounts which, in the event of an adverse judgment, could have a material adverse effect on our results of operations, financial condition and cash flows.

Legal Matters.

In connection with several of the following proceedings, CenterPoint and certain of its subsidiaries are parties to such proceedings. Pursuant to our indemnity agreement with CenterPoint, we have assumed the

defense and related indemnity obligations arising from claims against CenterPoint and its subsidiaries in each of the related proceedings.

Class Action Lawsuits

Western States Electricity Class Actions. Certain of our operating subsidiaries have been named, along with a number of other defendants, including a subsidiary of CenterPoint, as defendants in class action lawsuits in California. In general, the plaintiffs allege that our operating subsidiaries unlawfully conspired to increase wholesale electricity prices in California from 2000 to 2001. The lawsuits seek injunctive relief, treble damages, restitution of overpayments, disgorgement of unlawful profits and legal expenses. These lawsuits fall into three groups:

- The first group consists of six lawsuits originally filed in the fourth quarter of 2000 and the first quarter of 2001 and subsequently consolidated in one proceeding before the United States District Court for the Southern District of California. In December 2002, the court ordered that the six lawsuits be tried in California state court. The court's order is under appeal before the United States Court of Appeals for the Ninth Circuit.
- The second group consists of eight lawsuits originally filed in the second quarter of 2002 and subsequently consolidated into one proceeding before the United States District Court for the Southern District of California. In August 2003, the court dismissed seven of the eight cases on the basis of federal preemption and the filed rate doctrine, the eighth case not having been served on any of the defendants. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit.
- The third group consists of a multi-state class action lawsuit filed in May 2003 against an operating company of our wholesale energy segment and a subsidiary of CenterPoint that is currently pending before the United States District Court for the Southern District of California.

Snohomish County PUD Class Action. In July 2002, the Snohomish County Public Utility District (PUD) filed a lawsuit on behalf of itself and its customer-owners against one of our wholesale energy segment operating companies, along with a number of other defendants. The plaintiffs allege manipulation of the price of electricity purchased by the utility for its customers in violation of California's antitrust and unfair and unlawful business practices laws. In January 2003, the United States District Court for the Southern District of California dismissed the lawsuit on the basis of federal preemption and the filed rate doctrine. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit.

Natural Gas Class Actions. We, and certain of our operating companies, along with a number of other defendants, including a subsidiary of CenterPoint, are parties to two class action lawsuits consolidated before the United States District Court of Nevada, and a third that has been conditionally transferred to the United States District Court of Nevada from the United States District Court for the Eastern District of California. In each of the three suits, the plaintiffs allege a conspiracy to increase the price of natural gas in California in violation of the Cartwright Act and California's antitrust and unfair and unlawful business practices laws. In one of the lawsuits, the plaintiffs allege violations of the federal Sherman Act. The lawsuits seek injunctive and declaratory relief, treble the amount of damages, restitution, disgorgement of unjust enrichment, costs of suit and attorneys' fees.

A fourth class action was filed in February 2004, in Superior Court of the State of California, San Diego County against one of our operating subsidiaries and a number of other defendants. Similar to the other class actions, plaintiffs allege a conspiracy to increase the price of natural gas in California in violation of the Cartwright Act and California's antitrust and unfair and unlawful business practices laws. The plaintiffs seek injunctive and declaratory relief, treble the amount of damages, disgorgement of unjust enrichment, costs of suit and attorneys' fees.

We and certain of our operating companies, along with a number of other defendants, are also parties to a taxpayer representative lawsuit filed in November 2002 by the California Lieutenant Governor in the Superior Court of the State of California, Los Angeles County on behalf of purchasers of gas and power in California. The plaintiff alleges a conspiracy to increase the price of natural gas in California in violation of the Cartwright Act and California's antitrust and unfair and unlawful business practices laws. The lawsuit seeks injunctive and declaratory relief, treble damages, restitution and legal fees.

Natural Gas Futures Complaints. Certain of our wholesale energy segment operating companies and a subsidiary of CenterPoint are defendants in three class action lawsuits pending before the United States District Court for the Southern District of New York (originally filed in August, October and November 2003, respectively). The plaintiffs in each case allege that the defendants manipulated the price of natural gas and thereby influenced natural gas futures traded on the New York Mercantile Exchange in violation of the Commodity Exchange Act, and seek unspecified damages on behalf of themselves and the respective putative class members.

State Attorney General Lawsuits/Complaints

California Attorney General Actions. In March 2002, the California Attorney General filed a lawsuit against Reliant Resources, a subsidiary of CenterPoint and several of our wholesale energy segment operating companies. The lawsuit alleged violations of state laws against unfair and unlawful business practices arising out of transactions in the markets for ancillary services run by the California Independent System Operator (Cal ISO). The lawsuit sought injunctive relief, disgorgement of our alleged unlawful profits for sales of electricity and civil penalties. In March 2003, the United States District Court for the Northern District of California dismissed this lawsuit on the basis of federal preemption and the filed rate doctrine. The California Attorney General has appealed to the United States Court of Appeals for the Ninth Circuit.

In March 2002, the California Attorney General filed a complaint against two of our wholesale energy segment operating companies with the FERC. The complaint alleges that the failure of our operating companies to file transaction-specific information about sales and purchases resulted in a refund obligation to the extent that such transactions took place at prices above "just and reasonable" rates. In May 2002, the FERC denied the complaint but ordered our operating companies to file revised transaction reports regarding prior sales in California spot markets. In September 2002, the California Attorney General petitioned the United States Court of Appeals for the Ninth Circuit for review of FERC's decision.

In April 2002, the California Attorney General sued Reliant Resources, a subsidiary of CenterPoint, and several of our wholesale energy segment operating companies. The lawsuit is substantially similar to the complaint filed with the FERC described above. In addition, the lawsuit alleges that we charged unjust and unreasonable prices for electricity and that each unjust charge violated California law. The lawsuit seeks fines of up to $2,500 for each alleged violation and other equitable relief. In March 2003, the United States District Court for the Northern District of California dismissed this lawsuit on the basis of federal preemption and the filed rate doctrine. The California Attorney General has appealed to the United States Court of Appeals for the Ninth Circuit.

In April 2002, the California Attorney General and the California Department of Water Resources (CDWR) sued Reliant Resources, a subsidiary of CenterPoint and several of our wholesale energy segment operating companies in the United States District Court for the Northern District of California. The plaintiffs allege that our acquisition of electric generating facilities from Southern California Edison in 1998 violated Section 7 of the Clayton Act, which prohibits mergers or acquisitions that substantially lessen competition. The lawsuit alleges that the acquisitions gave us market power, which we then exercised to overcharge California consumers for electricity. The lawsuit seeks injunctive relief against alleged unfair competition, divestiture of our California facilities, disgorgement of alleged illegal profits,

damages and civil penalties for each alleged exercise of illegal market power. In March 2003, the court dismissed the plaintiffs' claim for damages under Section 7 of the Clayton Act but declined to dismiss the plaintiffs' injunctive claim for divestiture of our California facilities.

Montana Attorney General Action. On June 30, 2003, the Montana Attorney General and Flathead Electric Cooperative sued one of our wholesale energy segment operating companies, along with a number of other defendants, in the First Judicial District Court of Montana, County of Lewis and Clark. The plaintiffs allege that, together with other energy and trading company defendants named in the suit, our operating companies conspired to restrain trade and to fix and manipulate the price for electricity and natural gas in violation of various provisions of Montana's Unfair Trade Practices and Consumer Protection Act. The lawsuit seeks injunctive relief, treble the amount of damages alleged, costs of suit and attorneys' fees, but has not been served on any of the defendants.

Private Litigants

Sierra Pacific Resources and Nevada Power Company. In November 2003, Nevada Power Company named us as a defendant in arbitration before the American Arbitration Association. Nevada Power alleges that we conspired to drive up the price of natural gas in violation of various state and federal laws. Nevada Power seeks $15 million in the arbitration for its alleged damages.

Los Angeles Department of Water and Power (LADWP). In July 2003, the City of Los Angeles sued Reliant Resources, CenterPoint and one of our wholesale energy segment operating companies in the Superior Court in California. The case has been conditionally removed to the United States District Court of Nevada to proceed with the natural gas class actions discussed above. The lawsuit alleges that we conspired to manipulate the price for natural gas in breach of our contract to supply LADWP with natural gas and in violation of federal and state antitrust laws, the federal Racketeer Influenced and Corrupt Organization Act and the California False Claims Act. The lawsuit seeks treble damages for the alleged overcharges for gas purchased by LADWP, which it estimates at $218 million, interest, and legal costs. The lawsuit also seeks a determination that an extension of the contract with LADWP was invalid in that required municipal approvals for the extension were allegedly not obtained.

In January of 2004, the City of Los Angeles filed a similar lawsuit against us and other natural gas trading and marketing companies in California Superior Court. The lawsuit alleges many of the same state law claims but does not allege the federal law claims included in the first lawsuit.

Nevada Power and PacificCorp Complaints. In June 2003, the FERC denied a series of complaints filed by Nevada Power Company and PacificCorp, which sought reformation of certain forward power contracts those companies had with several counterparties, including one of our subsidiaries. The complainants have appealed.

Texas Commercial Energy. In July 2003, Texas Commercial Energy, LLP filed a lawsuit against us and several other participants in the ERCOT power market in the Corpus Christi Federal District Court for the Southern District of Texas. The plaintiff, a retail electricity provider in the ERCOT market, alleges that the defendants committed violations of state and federal antitrust laws, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract and civil conspiracy. The lawsuit seeks damages in excess of $535 million, exemplary damages, treble damages, interest, costs of suit and attorneys' fees. In November 2003, two other retail electric providers in the ERCOT market requested to intervene in this action as plaintiffs making factual allegations similar to those made by Texas Commercial Energy, LLP and seeking the same kinds of relief, although not specifying the amount of damages they seek. The intervention motion and the motions to dismiss Texas Commercial Energy, LLP's complaint are set for hearing in May 2004.

Bankruptcy of Enron Corp. and Its Affiliates. In the fourth quarter of 2001, Enron Corp. filed a voluntary petition for bankruptcy. Accordingly, we recorded a $68 million provision, comprised of provisions against 100% of Enron receivables of $79 million offset by net trading and derivative balances of $11 million. In 2002, we sued Enron Canada Corp., the only Enron party to our netting agreement which is not in bankruptcy, in United States District Court for the Southern District of Texas to recover $78 million (an amount which reflects the netting pursuant to the netting agreement of amounts among various Enron subsidiaries and our subsidiaries). The case is pending. However, in January 2003, Enron sued us in United States Bankruptcy Court for the Southern District of New York claiming $13 million based on the unenforceability of the netting agreement.

In November 2003, Enron Canada Corp., which is seeking to enjoin our lawsuit against it in Texas, initiated a lawsuit in Canada involving a gas purchase and sale contract underlying our netting agreement. Enron Canada Corp. asserts that the netting agreement is unenforceable and that our Canadian subsidiary has therefore breached the gas purchase and sale agreement by failing to pay approximately $4 million under the gas purchase and sale agreement. Enron Canada Corp. alleges that we are also liable for this amount under a guarantee. We have not yet been served in this lawsuit.

In addition, on December 1, 2003, a subsidiary of Enron Corp. sued one of our subsidiaries, Reliant Energy Services, Inc. (Reliant Energy Services), in United States Bankruptcy Court for the Southern District of New York for $85 million. Enron alleges that a series of related natural gas financial swap transactions executed by and among Enron, Reliant Energy Services and the Bank of Montreal on November 5, 2001, resulted in set-offs against debts with Enron, which should be invalidated under the preference, set-off and fraudulent conveyance provisions of the bankruptcy code.

The non-trading derivatives with Enron were designated as cash flow hedges (see note 7). The unrealized net gain on these derivative instruments previously reported in other comprehensive income (loss) will remain in accumulated other comprehensive loss and will be reclassified into earnings during the period in which the originally forecasted transactions occur. During 2002 and 2003, $52 million gain and $3 million loss, respectively, was reclassified into earnings related to these cash flow hedges. As of December 31, 2002 and 2003, the remaining amount to be reclassified into earnings through 2007 was $6 million and $3 million of losses, respectively.

RMF Industrial Contracting, Inc. In July 2003, a subcontractor participating in the construction of our 521 MW electric generating facility, the Seward project, filed a mechanics' lien in the amount of $36 million against property owned by one of our subsidiaries. The subcontractor has alleged that the contractor for the Seward project prevented the subcontractor from completing its work on the project and failed to pay it for work performed on the project. The terms of the engineering, procurement and construction contract for the project permits our subsidiary to withhold payments to the contractor to protect itself against the possibility that the lien is found to be valid, and requires the contractor to indemnify and hold our subsidiary harmless from the mechanics' lien and the cost of defending related actions. As of March 1, 2004, our subsidiary has withheld payments to the contractors in an aggregate amount exceeding $36 million. The existence of the mechanics' lien does not constitute a default or an event of default under any of our, or our subsidiaries' credit agreements. The matter is pending before the United States District Court for the Western District of Pennsylvania.

PUCT Cases. Since 2002, the PUCT has approved various increases to the fuel factor component contained in our "price-to-beat." Parties opposing the increases have filed for judicial review of the PUCT's orders in state district court in Travis County, Texas. To date, the court has affirmed the first PUCT ruling. While the other rulings are pending at the district court, the parties opposing the increases, have appealed the district court's decision. In each of these proceedings we are vigorously contesting the appeal.

Trading and Marketing Investigations

FERC Investigations of Western Market Issues. In October 2003, we entered into a settlement agreement with the FERC resolving its investigations and proceedings in connection with its ongoing review of western energy markets (exclusive of pending FERC proceedings concerning refund obligations in connection with wholesale electricity sales into the Cal ISO and California Power Exchange (Cal PX) markets, as described below in note 15(b), and the gaming show cause proceedings, described below). The settlement provides that:

- We make three cash settlement payments, totaling $25 million, into a fund established for the benefit of California and western market electricity consumers. In October 2003, we paid $15 million into the fund; additional payments of $5 million each shall be made in September 2005 and 2006;
- We offer capacity from a portion (totaling 824 MW) of our generation portfolio in California to the market for one-year terms for delivery commencing in 2004, 2005, and 2006 on a unit-contingent, gas-tolling basis; we will pay the difference, up to $25 million, between the collected auction revenues and our projected cash costs to generate the power into the fund described above; the requirement to offer this capacity to the market ceases at the earlier of three years, or the point in time when projected auction revenues less our cost to generate power reach $25 million; and
- Until October 2004, our sales in the western power markets will be subject to review, and we will report sales data to the FERC on a transaction-by-transaction basis; we have also made other commitments in the settlement regarding providing information to the FERC upon request.

In 2003, we offered, but did not receive qualifying bids for, capacity from the 824 MW portion of our California generation portfolio for the 12-month period beginning April 1, 2004. Although the units will be subject to up to two more auctions, we have mothballed the units comprising this portion of our California generation portfolio.

Under the terms of the settlement, we retain the ability to make sales of power at market-based rates. The FERC also found no reason to investigate us further with respect to physical withholding of power. In addition, the FERC addressed in the settlement the issues surrounding our trading of natural gas at the Topock, Arizona delivery point that had been raised in a March 2003 report by the FERC staff. The FERC found that our trading activities did not violate either the Natural Gas Act or any FERC regulations, that there was no evidence of any intent by our trader or us to manipulate the price of natural gas and that, as a result, no remedy was necessary.

In 2003, we recognized a $37 million pre-tax loss for the settlement based on (a) the present value ($24 million) of the cash settlement payments ($25 million) and (b) the fair value of our obligation to offer capacity from our power generation portfolio ($13 million) during 2005 and 2006, based on an option valuation model. The amount of the liability ascribed to each auction period will be offset against the payments required to be made to the FERC, if any, resulting from contracts entered into as a result of such auction. If there are no contracts that result from an auction, the associated liability for that period will be reversed in the period that the auction occurs.

The gaming show cause proceedings involve allegations that certain of our subsidiaries unlawfully gamed the California markets by engaging in double selling and paper trading of ancillary services and by engaging in so-called ricochet trades. The FERC staff found no foundation to the allegations that our subsidiaries engaged in paper trading, ricochet transactions or collusive gaming practices. While not admitting the allegations of double selling of ancillary services, our subsidiaries entered into a settlement with the FERC in which we agreed to pay $836,000 in resolution of allegations of double selling. The settlement resolved related allegations of double selling of ancillary services made by the Cal ISO in July

2003 against our operating subsidiaries and the Cal ISO's proposed rescission of approximately $11 million paid to us. The FERC denied the proposed rescission and found that all allegations of double selling of ancillary services were to be resolved in the gaming show cause proceedings.

In January 2003, in connection with the FERC's investigation of potential manipulation of electricity and natural gas prices in the Western United States, the FERC approved a stipulation and consent agreement between the FERC staff and us relating to certain actions taken by some of our traders over a two-day period in June 2000. Under the agreement, we agreed to pay $14 million (which was expensed in the fourth quarter of 2002) directly to customers of the Cal PX and certain other terms, including a requirement to abide by a must offer obligation to submit bids for all of our uncommitted, available capacity from our plants located in California into a California spot market one additional year following termination of our existing must offer obligation or until December 31, 2006, whichever is later.

Investigations by the CFTC. In November 2003, we entered into a settlement with the Commodity Futures Trading Commission (CFTC) in connection with an investigation relating to trading and price reporting issues. The settlement addressed the reporting of natural gas trading information to energy industry publications that compile and report index prices and seven offsetting and pre-arranged electricity trades that were executed on an electronic trading platform in 2000. Pursuant to the terms of the settlement, without admitting or denying liability, one of our subsidiaries agreed to pay a civil monetary penalty of $18 million, which was paid and expensed in the fourth quarter of 2003.

Investigations by United States Attorneys. We have received subpoenas and informal requests from the United States Attorneys for the Southern District of New York, the Southern District of Texas and the Northern District of California for documents, interviews and other information pertaining to "round trip trades," price reporting and alleged price manipulation. We have produced information to each of the United States Attorneys' offices. The United States Attorney for the Southern District of New York has closed its investigation.

In response to July 24, 2003, Grand Jury subpoenas, a number of current and former employees have given interviews to the United States Attorney for the Northern District of California or testified before the Grand Jury investigating allegations of electricity price manipulation. On March 5, 2004, the United States Attorney's office for the Northern District of California informed our counsel that it intends to seek a criminal indictment against our subsidiary, Reliant Energy Services, and certain of its current and former employees (none of whom is an officer of Reliant Resources), alleging price manipulation based on the curtailment of electricity generation in California on two days in June 2000. The allegation of price manipulation during this two-day period was the subject of the settlement with the FERC in January 2003 described above. In our settlement, we neither admitted nor denied that these actions affected prices in any market, or violated any law, tariff or regulation.

We do not believe that our subsidiary engaged in actions in violation of laws, tariffs or regulations in effect at the time and intend vigorously to contest the allegations. We do not believe that this action against our subsidiary will have a material impact on our ongoing business operations, including any impact on our credit or debt agreements, the wholesale license held by our subsidiary, the retail and wholesale licenses held by our other subsidiaries or contracts and agreements to which our subsidiary is a party.

The United States Attorney for the Southern District of Texas is currently investigating natural gas reporting price issues. This investigation could result in civil or criminal actions being brought against us, certain of our subsidiaries or our current or former employees.

Shareholder Class Actions

We are defendants in 15 class action lawsuits filed on behalf of purchasers of our securities and the securities of CenterPoint. The lawsuits allege that the defendants violated federal securities laws by, among other things, making false and misleading statements about trading volumes and revenues. The lawsuits seek monetary damages on behalf of persons who purchased CenterPoint securities during specified class periods. In August 2002, the shareholder lawsuits were consolidated into one proceeding before the United States District Court, Southern District of Texas, Houston Division. In March 2003, we and the other defendants filed a motion to dismiss certain of the claims. In January 2004, the court dismissed with prejudice the federal and state securities fraud claims. With the dismissal of all fraud-related claims, the only remaining claims against us are claims under Section 11 and 15 of the Securities Act of 1933 pertaining to statements made in our registration statement for our initial public offering.

Illinois Shareholder Lawsuit. On February 7, 2003, a lawsuit was filed against CenterPoint and certain of our former and current employees in United States District Court for the Northern District of Illinois, Eastern Division. The plaintiffs allege violations of federal securities law, Illinois common law and the Illinois Consumer Fraud and Deceptive Trade Practices Act. The lawsuit makes allegations similar to those made in the other class action lawsuits and seeks treble damages and legal expenses. In January 2004, the court dismissed the action for failing plead facts supporting plaintiffs' claims, but also granting plaintiffs leave to file an amended complaint to attempt to cure the pleading defects.

ERISA Action. On May 30, 2002, a class action lawsuit was filed in the United States District Court, Southern District of Texas, Houston Division against us and CenterPoint, on behalf of participants in our and CenterPoint's employee benefits plans. The lawsuit alleges breach of fiduciary duties in violation of the Employee Retirement Income Security Act in connection with investment decisions made by the plans in CenterPoint and our securities. The lawsuit seeks monetary damages and restitution. In May 2003, the defendants filed a motion to dismiss the claims. In January 2004, the court dismissed us as a defendant from this proceeding on standing grounds. CenterPoint, and certain members of CenterPoint's benefits committee, remain in this case.

Shareholder Derivative Actions

Derivative Lawsuit. On May 17, 2002, a derivative lawsuit was filed against our directors and independent auditors in the 269th Judicial District, Harris County, Texas. The lawsuit alleges that the defendants breached their fiduciary duties to us by causing us to conduct our business in an imprudent and unlawful manner. Among other things, the lawsuit cites (a) alleged failures to implement and maintain an adequate internal accounting control system, (b) "round trip trading transactions" (including the dissemination of materially misleading and inaccurate information regarding revenue and trading volume) and (c) withholding power in the California market in June 2000. The lawsuit seeks monetary damages on our behalf.

In December 2002, our board of directors appointed a special litigation committee to investigate the claims asserted in the lawsuit. The special litigation committee was assisted in its investigation by external counsel appointed by the committee. In December 2003, the special litigation committee determined that it would not be in our best interest to proceed with the derivative lawsuit. The special litigation committee has asked the court to dismiss the suit.

Environmental Matters.

REMA Ash Disposal Site Closures and Site Contaminations. REMA is responsible for environmental costs related to (a) the closure of six ash disposal sites and (b) site contamination investigations and remediation requirements at four of its generation facilities. Based on our evaluations with assistance from third-party consultants and engineers, we have recorded the estimated aggregate costs associated with these

environmental liabilities of $35 million and $23 million as of December 31, 2002 and 2003, respectively, of which we expect to spend $8 million over the next five years.

Orion Power Environmental Contingencies. Orion Power is liable under the terms of a consent order issued in 2000 with the New York State Department of Environmental Conservation (NYSDEC) for past releases of petroleum and other substances at two of its generation facilities. Based on our evaluations with assistance from third-party consultants and engineers, we have developed remediation plans for both facilities. As of December 31, 2002 and 2003, we have recorded the estimated liability for the remediation costs of $8 million and $7 million, respectively, which we expect to pay out through 2008.

Under a separate consent order issued by the NYSDEC in 2000, Orion Power is required to evaluate certain technical changes to modify the intake cooling system of one of its plants. Orion Power and the NYSDEC will discuss the technical changes to be implemented. Depending on the outcome of these discussions, including the form of technology ultimately selected, we estimate that capital expenditures necessary to comply with the order could meet or exceed $87 million. We expect to begin construction on a portion of the cooling water intake in 2004.

Orion Power is responsible for environmental liabilities associated with the future closure of three ash disposal sites in Pennsylvania. As of December 31, 2002 and 2003, the total estimated liability determined by management with assistance from third-party engineers and recorded by Orion Power for these disposal sites was $14 million and $11 million, respectively, of which $1 million is to be paid over the next five years.

New Source Review Matters. The United States Environmental Protection Agency (EPA) has requested information from six of our coal-fired facilities, as well as two of our Orion Power facilities, related to work activities conducted at the sites that may be associated with various permitting requirements of the Clean Air Act. We have responded to the EPA's requests for information. In addition to the EPA's requests for information, the New Jersey Department of Environmental Protection requested from the EPA a copy of all correspondence relating to the EPA's request for information for one of the six facilities, which request the EPA has granted. Furthermore, the New York state attorney general's office and the Pennsylvania Department of Environmental Protection recently requested from the EPA a copy of all such correspondence relating to all six facilities, which the EPA granted.

Other Matters.

We are involved in other legal and environmental proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. We believe that the effects on our financial statements, if any, from the disposition of these matters will not have a material adverse effect on our results of operations, financial condition or cash flows.

(b) California Energy Sales Credit and Refund Provisions.

As of December 31, 2003, our consolidated balance sheet included a $189 million net receivable, included in the $242 million below, for energy sales in California that relate to sales of power by us into the markets run by the Cal ISO and the Cal PX in 2000 and 2001.

The receivable remains outstanding as a result of defaults by purchasers of power in the Cal ISO and Cal PX markets in 2000 and 2001, primarily, the two investor owned utilities, Pacific Gas and Electric (PG&E) and Southern California Edison Company (SCE). The receivable is also the subject of the refund proceeding initiated by the FERC in 2001 regarding prices charged by our wholesale energy segment in California from October 2, 2000 through June 20, 2001.

SCE has paid to the Cal ISO and the Cal PX all amounts due by it on account of power purchases; however, no distributions have been made pending resolution of the FERC refund proceeding. PG&E filed

for protection under the bankruptcy laws in April 2001 and has not made payment on account of these pre-petition claims. In December 2003, the bankruptcy court confirmed PG&E's plan of reorganization. The plan of reorganization adopts a settlement agreement with the California Public Utilities Commission and calls for the payment of our claim, including interest thereon, in cash and in an amount determined by the FERC in the refund proceeding. There is an appeal and request for rehearing pending the bankruptcy confirmation order and the California Public Utilities Commission's order approving the settlement agreement, respectively.

We have receivables due from the Cal ISO, the Cal PX and the CDWR for energy sales in the California wholesale market during the fourth quarter of 2000 through December 31, 2003. Our gross receivables for California energy sales are adjusted for (a) an expected refund obligation, (b) a credit reserve and (c) interest receivable. The adjustments impacted our net receivables as follows:

	December 31,	
	2002	2003
	(In millions)	
Accounts receivable, excluding refund obligation	$306	$326
Refund obligation	(191)	(81)
Credit reserve	(6)	(21)
Interest receivable	5	18
Accounts receivable, net	$114	$242

During 2001, 2002 and 2003, we adjusted our estimated refund obligation and credit reserve (netted in revenues) and interest income (recorded in interest income) related to energy sales in California as follows (income (loss)):

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Refund obligation	$(15)	$(176)	$110
Credit reserve(1)	(29)	62	(15)
Interest receivable	—	5	13
Net impact on net income/loss	$(44)	$(109)	$108

(1) We recorded a credit reserve provision in 2000 of $39 million relating to energy sales in California; taken together with our impacts in 2001, 2002 and 2003, we have a net credit reserve of $21 million as of December 31, 2003.

FERC Refund Proceedings. We are a party to a refund proceeding initiated by the FERC in 2001 regarding wholesale electricity prices charged by our wholesale energy segment in California from October 2, 2000 through June 20, 2001.

Based on the refund methodology adopted by the FERC, we currently estimate our refund obligation to be between $81 million and $210 million for energy sales in California. We base this estimate on a number of assumptions:

- the amounts charged by us for wholesale electricity sales in California during the refund period as computed by the Cal ISO; and
- the refund methodology adopted by the FERC in July 2001, as modified in March 2003 and October 2003 (a) to use a "proxy" gas price based on producing area daily price indices plus posted transportation costs and (b) to permit a reduction in refund liability if actual gas costs

during the refund period exceeded allowed gas costs under the proxy gas price used in the FERC's refund formula.

The low end of the range of our estimate, which we have recorded, is based on a refund calculation factoring in a reduction in the total FERC refund based on (a) the actual cost paid for gas over the proposed proxy gas price and (b) exclusion of all purchases made by the CDWR from the refund calculation. The high end of the range of our estimate of the refund obligation assumes that the refund obligation is not adjusted for (a) the actual cost paid for gas over the proposed proxy gas price and (b) purchases made by the CDWR that were in excess of the amounts needed to meet the needs of the California utilities. We continue to assess our low and high ends of the range and our most probable estimate within that range based on the FERC orders which clarify/modify the refund calculation methodology and it is possible that we could have additional changes to our accrual and/or our range in the future.

During 2001, we established a $15 million reserve for potential refund obligations. During 2002, we recognized an additional reserve for potential refund obligations of $176 million resulting in a reserve of $191 million as of December 31, 2002. During 2003, we reversed $110 million of previously recorded refund provisions due to the decisions by the FERC in March and October 2003 permitting us to file to recover our actual gas costs to the extent they exceed the amount determined using the proxy gas price under the modified refund formula. As of December 31, 2003, our reserve for refunds related to energy sales in California was $81 million.

It is our current expectation that the amount of refunds we ultimately are determined to owe will be offset against our uncollected receivables for energy sales in California.

California Credit Provision. During 2000 and 2001, we recorded net pre-tax credit provisions against receivable balances related to energy sales in California of $39 million and $29 million, respectively, resulting in a pre-tax credit provision of $68 million as of December 31, 2001. During 2002, we reversed $62 million of this provision resulting in a $6 million provision as of December 31, 2002. The reversal in 2002 resulted from collections of outstanding receivables during the period, a determination that credit risk had been reduced on the remaining outstanding receivables as a result of payments in 2002 to the Cal PX and due to the write-off of receivables as a result of a May 2002 FERC order and related interpretations and a March 2003 FERC order discussed above. During 2003, we recorded additional credit provisions of $15 million due to the reversal of refund provisions discussed above. As of December 31, 2003, we had a remaining pre-tax credit provision of $21 million against these receivable balances. We will continue to assess the collectability of these receivables based on further developments in the FERC refund proceeding and will adjust the credit reserve to reflect the impact of such developments in the periods in which they occur.

Interest Calculation. During 2002 and 2003, we recorded net interest income of $5 million and $13 million, respectively. We estimated net interest income based on:

- the December 2002 findings of the presiding administrative law judge in the FERC refund proceeding, described above;
- the lowest range in our estimated potential refund;
- the receivable balance outstanding; and
- the quarterly interest rates for the applicable time period as designated by the FERC.

(c) Tolling Agreement for Liberty's Generating Station.

LEP owns a 530 MW combined cycle gas fired power generation facility (the Liberty generating station). Liberty financed the construction costs of the Liberty generating station with borrowings under a credit agreement of which $262 million is outstanding as of December 31, 2003. Borrowings under the

credit agreement, which are non-recourse to Reliant Resources and its affiliates (other than LEP and Liberty), are secured by pledges of the assets of the Liberty generating station and of the ownership interest in LEP. See note 9(a).

In July 2003, the counterparty to the tolling agreement under which LEP sold the generation output of the Liberty generation station filed for bankruptcy. Subsequently, a federal bankruptcy court issued an order that terminated the tolling agreement and triggered another event of default under the Liberty credit agreement. The default under the Liberty credit agreement, and the possible foreclosure by the lenders upon the assets of the Liberty generating station, do not constitute an event of default under any other debt agreements of Reliant Resources or its affiliates.

To date, the lenders under the Liberty credit agreement have not foreclosed upon the Liberty generating station. However, there can be no assurance that the lenders will continue to refrain from exercising such rights. If the lenders elect to foreclose on LEP, Liberty and/or the Liberty generating station, we could incur a pre-tax loss of an amount up to our recorded net book value, with the potential of an additional loss due to an impairment of goodwill to be allocated to LEP. As of December 31, 2003, the combined net book value of LEP and Liberty was $346 million, excluding the non-recourse debt obligations of $262 million. At December 31, 2002 and 2003, we evaluated the Liberty generating station and the related intangible asset for the terminated tolling agreement for impairment. Based on our analyses, there were no impairments.

In September 2003, LEP sued the corporate guarantor of the counterparty to the tolling agreement, Gas Transmission Northwest Corporation, seeking payment of $140 million (the maximum amount of the guarantee) out of the $177 million termination claim calculated by LEP under the agreement. Subsequently, the counterparty to the tolling agreement and its corporate guarantors countersued LEP seeking to collect a $108 million termination payment under the tolling agreement. The obligations of LEP under the tolling agreement are secured by a $35 million letter of credit issued under the senior secured revolver of Reliant Resources. If the letter of credit were to be drawn, Reliant Resources would be required to reimburse the issuing bank.

In light of current market conditions and the termination of the tolling agreement, LEP does not expect to have sufficient cash flow to pay both (a) all of its expenses and to post the collateral required to buy fuel or in respect of the gas transportation agreements and (b) debt service obligations. Liberty received temporary deferrals until April 2004 from its lenders for the quarterly principal installments that were due in October 2003 and January 2004, which aggregated $4 million. Based on the foregoing, we are exploring various strategic options with respect to our subsidiaries interest in the Liberty generating station, including, among other things, the execution of a foreclosure arrangement with the lenders resulting in a transfer of ownership to the lenders or a sale of our interest in the generating station. There can be no assurances regarding the outcome of this process. A foreclosure of our interest in the generation station would, however, result in an impairment of the asset on our balance sheet.

If LEP recovers the amount of the termination claim, the lenders are entitled to require that such amounts be used to pay deferred interest and to prepay debt under the Liberty credit agreement. Under United States and Pennsylvania tax laws, it is possible that receipt of a termination payment by LEP could be deemed taxable income to Reliant Resources and its other affiliates.

(16) Receivables Facility

In July 2002, we entered into a receivables facility arrangement with a financial institution to sell an undivided interest in our accounts receivable from residential and small commercial retail electric customers under which, on an ongoing basis, the financial institution could invest a maximum of $250 million for its interest in eligible receivables. This facility was amended in September 2003 to include a second financial institution, to include our accounts receivable from our large commercial, industrial and

institutional customers and to increase the facility to a maximum total of $350 million. Pursuant to the receivables facility, we formed a QSPE as a bankruptcy remote subsidiary. The QSPE was formed for the sole purpose of buying receivables generated by us and selling undivided interests to the financial institutions. The QSPE is a separate entity and its assets will be available first and foremost to satisfy the claims of its creditors. We, irrevocably and without recourse, transfer receivables to the QSPE. The QSPE, in turn, sells an undivided interest in these receivables to the participating financial institutions. We are not ultimately liable for any failure of payment of the obligors on the receivables. We have, however, guaranteed the performance obligations of the sellers and the servicing of the receivables under the related documents.

The amount of accounts receivable included under the arrangement may increase as certain accounts receivable become eligible, particularly from some of our large commercial, industrial, and institutional customers, and result in additional available funding. There can be no assurance that these accounts receivable will become eligible and result in additional available funding.

The two-step transaction described above is accounted for as a sale of receivables, which is recorded after the first step, and as a result the related receivables are excluded from our consolidated balance sheets. We continue to service the receivables and receive a fee of 0.5% of cash collected. The following table details the servicing fee income and costs associated with the sale of receivables:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Servicing fee income	$ 8	$ 18
Interest income	4	10
Loss on sale of receivables	(10)	(37)
Other expenses	(2)	(2)
Net costs	$ —	$(11)

The following table details the outstanding receivables that have been sold and the corresponding notes receivable from the QSPE, which have been reflected in our consolidated balance sheets:

	December 31,	
	2002	2003
	(In millions)	
Accounts receivable sold	$ 277	$ 528
Notes receivable from QSPE	(168)	(394)
Equity contributed to QSPE	(8)	(16)
Other accounts receivable from QSPE	(6)	—
Funding outstanding	$ 95	$ 118

The failure of the obligors to make payment on the receivables could result in our notes receivable from the QSPE not being fully realized. Texas Genco holds a senior lien on these notes receivable, while the senior secured note holders and the banks in our March 2003 credit facilities ratably hold a junior lien. See note 4 for further discussion.

The amount of funding available to us under the receivables facility fluctuates based on the amount of eligible receivables available and by the performance of the receivables portfolio. The following table

details the maximum amount under the receivables facility and the amount of funding outstanding as of December 31, 2002 and 2003:

	December 31,	
	2002	2003
	(In millions)	
Maximum amount under the receivables facility	$200	$ 350
Funding outstanding	(95)	(118)
Unused and unavailable amount	$105	$ 232

Prior to their sale, the book value of the accounts receivable is offset by the amount of the allowance for doubtful accounts and customer security deposits. In calculating the loss on sale for 2002 and 2003, an average discount rate of 5.40% and 8.40%, respectively, was applied to projected cash collections over a 6-month period. Our collection experience indicated that 98% of the accounts receivables would be collected within a 6-month period.

The receivables facility expires on September 28, 2004. If the receivables facility is not renewed on its termination date, the collections from the receivables purchased will repay the financial institutions' investment and no new receivables will be purchased under the receivables facility.

(17) Reliant Energy Communications

During 2001, management decided to exit our communications business. Consequently, we determined the goodwill associated with the communications business was impaired. We recorded a total of $54 million of pre-tax disposal charges in 2001. These charges included the write-off of goodwill of $19 million, fixed asset impairments of $22 million, and severance accruals and other incremental costs associated with exiting the communications business, totaling $13 million.

(18) Estimated Fair Value of Financial Instruments

The fair values of financial instruments, including cash and cash equivalents and trading and derivative assets and liabilities (see note 7), are equivalent to their carrying amounts in the consolidated balance sheets. The fair values of trading and derivative assets and liabilities as of December 31, 2002 and 2003 have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques, see note 7.

The carrying values and related fair market values of our short-term and long-term debt are detailed as follows (excluding adjustment to fair value of interest rate swaps and debt under our Liberty credit agreement):

	December 31,			
	2002		2003	
	Carrying Value(1)	Fair Market Value(1)(2)(3)	Carrying Value(1)	Fair Market Value(1)(3)
	(In millions)			
Fixed rate debt	$ 560	$409	$1,921	$1,992
Floating rate debt	5,936	N/A	3,910(4)	3,850(4)
Total debt, excluding adjustment to fair value of interest rate swaps and Liberty's debt	$6,496	N/A	$5,831	$5,842

(1) Excludes Liberty's fixed rate debt of $165 million and floating rate debt of $103 million and $97 million as of December 31, 2002 and 2003, respectively, as there was no active market for this debt. Due to the situation with Liberty (see note 15(c)), if the holders of Liberty's debt were to have tried to sell such debt instrument to a third party, the price which could have been realized would likely be substantially less than the face value of the debt instrument and substantially less than the carrying value.

(2) As of December 31, 2002, we had floating rate debt with a carrying value of $5.9 billion, excluding adjustment to fair value of interest rate swaps and Liberty's debt. There was no active market for our floating rate debt obligations as of December 31, 2002. Given our liquidity and credit situation as of December 31, 2002, if the holders of these borrowings were to have tried to sell such debt instruments to third parties, the prices which could have been realized could have been substantially less than the face values of the debt instruments and substantially less than our carrying values.

(3) The fair market values of our fixed rate debt (December 31, 2002 and 2003) and floating rate debt (for December 31, 2003 only) were based on (a) our incremental borrowing rates for similar types of borrowing arrangements or (b) information from market participants. For $2.0 billion of our floating rate debt, the carrying value equals the fair market value.

(4) Each of these amounts includes the values related to the outstanding warrants. See note 9.

(19) Supplemental Guarantor Information

For the two issuances of senior secured notes in July 2003 totaling $1.1 billion, our wholly-owned subsidiaries are either (a) full and unconditional guarantors, jointly and severally, (b) limited guarantors or (c) non-guarantors.

The primary full and unconditional guarantors of these senior secured notes are: Reliant Energy Aurora, LP; Reliant Energy California Holdings, LLC; Reliant Energy Electric Solutions, LLC; Reliant Energy Northeast Holdings, Inc.; REPG; Reliant Energy Retail Holdings, LLC; Reliant Energy Retail Services, LLC; Reliant Energy Services; Reliant Energy Shelby County II, LP and Reliant Energy Solutions, LLC.

Orion Power Holdings is the only limited guarantor of these senior secured notes and its guarantee of both the March 2003 credit facilities and the senior secured notes is limited to approximately $1.1 billion.

The primary non-guarantors of these senior secured notes are: Astoria Generating Company, LP; Erie Boulevard Hydropower, LP; Liberty; LEP; Orion Capital; Orion MidWest; Orion Power MidWest LP, LLC; Orion NY; Orion Power New York LP, LLC; Reliant Energy Capital (Europe), Inc. (RECE); Channelview; Reliant Energy Europe, Inc. (REE); Reliant Energy Trading & Marketing, B.V. (sold in December 2003); REMA; Reliant Energy New Jersey Holdings, LLC; Reliant Energy Power Generation Benelux, N.V. (sold in December 2003) and Reliant Energy Europe B.V. (RE BV) (sold in December 2003). All subsidiaries of Orion Power Holdings are non-guarantors. In connection with the sale of our European energy operations in December 2003, the majority of our European entities were sold. Effective February 2004, after the sale of our European energy operations, the following entities formerly classified as non-guarantors, became full and unconditional guarantors: RECE and REE. No adjustments to the disclosures for 2001, 2002 or 2003 were made for this change as the change will be made prospectively beginning in 2004. However, it is expected that these entities formerly in our European energy operations will have an insignificant amount of activity and/or balances.

Each of Astoria Generating Company, L.P., Carr Street Generating Station, LP, Erie Boulevard Hydropower, LP, Orion Capital, Orion MidWest, Orion Power MidWest LP, LLC, Orion Power MidWest GP, Inc., Orion NY, Orion Power New York LP, LLC, Orion Power New York GP, Inc. and Twelvepole Creek, LLC is a separate legal entity and has its own assets.

The following condensed consolidating financial information presents supplemental information for the indicated groups as of December 31, 2002 and 2003 and for 2001, 2002 and 2003:

Condensed Consolidating Statements of Operations.

	Year Ended December 31, 2001				
	Reliant Resources	Guarantors	Non-Guarantors	Adjustments(1)	Consolidated
			(In millions)		
Revenues	$ —	$5,075	$596	$(172)	$5,499
Trading margins	—	402	(23)	(1)	378
Total	—	5,477	573	(173)	5,877
Fuel and cost of gas sold	—	1,475	191	(90)	1,576
Purchased power	—	2,580	—	(82)	2,498
Operation and maintenance	—	257	193	11	461
General, administrative and development	102	285	96	(12)	471
Depreciation and amortization	2	115	53	—	170
Total	104	4,712	533	(173)	5,176
Operating (loss) income	(104)	765	40	—	701
Gains from investments, net	—	23	—	—	23
Income of equity investments	—	7	—	—	7
Income of equity investments of consolidated subsidiaries	567	36	—	(603)	—
Other, net	—	—	2	—	2
Interest expense	(10)	—	(6)	—	(16)
Interest income	—	19	3	—	22
Interest income (expense) — affiliated companies, net	129	35	(152)	—	12
Total other income (expense)	686	120	(153)	(603)	50
Income (loss) from continuing operations before income taxes	582	885	(113)	(603)	751
Income tax expense (benefit)	9	321	(40)	—	290
Income (loss) from continuing operations	573	564	(73)	(603)	461
(Loss) income from discontinued operations before income taxes	(16)	2	97	—	83
Income tax benefit	(6)	2	(12)	—	(16)
(Loss) income from discontinued operations	(10)	—	109	—	99
Income before cumulative effect of accounting change	563	564	36	(603)	560
Cumulative effect of accounting change, net of tax	—	3	—	—	3
Net income	$ 563	$ 567	$ 36	$(603)	$ 563

	Year Ended December 31, 2002					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
Revenues	$ —	$9,456	$ —	$ 1,744	$ (612)	$10,588
Trading margins	—	279	—	9	—	288
Total	—	9,735	—	1,753	(612)	10,876
Fuel and cost of gas sold	—	724	—	616	(258)	1,082
Purchased power	—	7,704	—	71	(354)	7,421
Accrual for payment to CenterPoint Energy, Inc.	—	128	—	—	—	128
Operation and maintenance	—	335	—	429	21	785
General, administrative and development	39	489	10	112	(21)	629
Impairment of goodwill(2)	—	—	—	337	(337)	—
Depreciation and amortization	15	140	—	213	—	368
Total	54	9,520	10	1,778	(949)	10,413
Operating (loss) income	(54)	215	(10)	(25)	337	463
Losses from investments, net	—	(23)	—	—	—	(23)
Income of equity investments	—	18	—	—	—	18
Loss of equity investments of consolidated subsidiaries	(524)	(820)	(230)	—	1,574	—
Loss on sale of receivables	—	(10)	—	—	—	(10)
Other, net	—	14	—	—	1	15
Interest expense	(116)	(2)	(39)	(110)	—	(267)
Interest income	9	12	1	7	(1)	28
Interest income (expense) — affiliated companies, net	106	43	—	(144)	—	5
Total other expense	(525)	(768)	(268)	(247)	1,574	(234)
(Loss) income from continuing operations before income taxes	(579)	(553)	(278)	(272)	1,911	229
Income tax (benefit) expense	(19)	124	(21)	22	—	106
(Loss) income from continuing operations	(560)	(677)	(257)	(294)	1,911	123
Income (loss) from discontinued operations before income taxes	—	115	—	(456)	—	(341)
Income tax expense	—	42	—	66	—	108
Income (loss) from discontinued operations	—	73	—	(522)	—	(449)
Loss before cumulative effect of accounting changes	(560)	(604)	(257)	(816)	1,911	(326)
Cumulative effect of accounting changes, net of tax	—	—	—	(234)	—	(234)
Net loss	$(560)	$ (604)	$(257)	$(1,050)	$1,911	$ (560)

	Year Ended December 31, 2003					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
Revenues	$ —	$9,744	$ —	$2,162	$ (857)	$11,049
Trading margins	—	(38)	—	(11)	—	(49)
Total	—	9,706	—	2,151	(857)	11,000
Fuel and cost of gas sold	—	940	—	925	(451)	1,414
Purchased power	—	7,378	—	59	(406)	7,031
Accrual for payment to CenterPoint Energy, Inc.	—	47	—	—	—	47
Operation and maintenance	—	344	—	497	24	865
General, administrative and development	—	356	3	217	(24)	552
Wholesale energy goodwill impairment(2)	—	126	—	585	274	985
Depreciation and amortization	11	158	—	250	—	419
Total	11	9,349	3	2,533	(583)	11,313
Operating (loss) income	(11)	357	(3)	(382)	(274)	(313)
Gains from investments, net	—	1	—	1	—	2
Loss of equity investments	—	(2)	—	—	—	(2)
Loss of equity investments of consolidated subsidiaries	(1,177)	(436)	(529)	—	2,142	—
Loss on sale of receivables	—	(37)	—	—	—	(37)
Other, net	—	—	—	9	—	9
Interest expense	(379)	(11)	(41)	(133)	48	(516)
Interest income	4	28	—	3	—	35
Interest income (expense)–affiliated companies, net	169	(16)	—	(105)	(48)	—
Total other expense	(1,383)	(473)	(570)	(225)	2,142	(509)
Loss from continuing operations before income taxes	(1,394)	(116)	(573)	(607)	1,868	(822)
Income tax (benefit) expense	(68)	182	(17)	(17)	—	80
Loss from continuing operations	(1,326)	(298)	(556)	(590)	1,868	(902)
(Loss) income from discontinued operations before income taxes	(16)	87	—	(318)	(63)	(310)
Income tax (benefit) expense	—	31	—	75	—	106
(Loss) income from discontinued operations	(16)	56	—	(393)	(63)	(416)
Loss before cumulative effect of accounting changes	(1,342)	(242)	(556)	(983)	1,805	(1,318)
Cumulative effect of accounting changes, net of tax	—	(42)	—	18	—	(24)
Net loss	$(1,342)	$ (284)	$(556)	$ (965)	$1,805	$(1,342)

(1) These amounts relate to either (a) eliminations and adjustments recorded in the normal consolidation process or (b) reclassifications recorded due to differences in classifications at the subsidiary levels compared to the consolidated level.

(2) Based on Orion Power Holdings and its subsidiaries' annual goodwill impairment test as of November 1, 2002, Orion Power's consolidated goodwill was impaired by $337 million, which was recognized in the fourth quarter of 2002. Impairments related to Orion Power have been reflected in the non-guarantor column since Orion Power uses push-down accounting for acquired subsidiaries. However, for continuing operations at a consolidated level, we did not have an impairment of goodwill during 2002. The Orion Power impairment loss was eliminated from Reliant Resources consolidated financial statements, as goodwill was not impaired at the higher level reporting unit, as of December 31, 2002. Based on our wholesale energy reporting unit's goodwill impairment test as of July 2003, we recognized an impairment of $985 million on a consolidated basis in the third quarter of 2003. Due to this impairment at the consolidated level, we concluded that it was more likely than not that there would be impairments at the subsidiary level for entities within the wholesale energy reporting unit. We therefore performed an updated impairment analysis for Orion Power Holdings and its subsidiaries as of July 2003. This test resulted in an impairment of $585 million on an Orion Power consolidated basis, which was recognized in the third quarter of 2003 in the non-guarantor column. When combined with the $337 million impairment recognized in 2002, Orion Power Holdings and its consolidated subsidiaries have recorded a cumulative impairment of $922 million as of December 31, 2003. Other than Orion Power Holdings' subsidiaries' goodwill, the only other goodwill recorded in entities within the wholesale energy reporting unit (other than $4 million related to REMA), totaling $177 million prior to this review, was recorded in the guarantor column and was derived from companies for which we are not required to prepare separate financial statements. We recognized $126 million of impairment in the guarantor column in the third quarter of 2003. This estimate reflects the difference between the consolidated Reliant Resources' impairment and the cumulative impairments recorded by Orion Power Holdings and subsidiaries and is supported by management's belief that this remaining amount of impairment is primarily associated with the wholesale energy reporting unit's entities that are guarantors.

Condensed Consolidating Balance Sheets.

	December 31, 2002					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
ASSETS						
Current Assets:						
Cash and cash equivalents	$ 657	$ 403	$ 6	$ 49	$ —	$ 1,115
Restricted cash	—	—	—	213	—	213
Accounts and notes receivable, principally customer, net	121	944	46	231	—	1,342
Accounts and notes receivable — affiliated companies	817	853	—	405	(2,075)	—
Inventory	—	129	—	146	—	275
Trading and derivative assets	—	557	—	109	—	666
Other current assets	21	354	1	177	(39)	514
Current assets of discontinued operations	2	11	—	651	—	664
Total current assets	1,618	3,251	53	1,981	(2,114)	4,789
Property, plant and equipment, gross	142	2,026	1	5,244	—	7,413
Accumulated depreciation	(21)	(185)	—	(216)	—	(422)
Property, Plant and Equipment, net	121	1,841	1	5,028	—	6,991
Other Assets:						
Goodwill, net(2)	—	210	—	994	337	1,541
Other intangibles, net	—	116	—	621	—	737
Notes receivable — affiliated companies	2,539	2,019	—	484	(5,042)	—
Equity investments	—	103	—	—	—	103
Equity investments in consolidated subsidiaries	5,715	273	3,283	—	(9,271)	—
Trading and derivative assets	—	199	—	65	—	264
Restricted cash	7	—	—	—	—	7
Other long-term assets	62	104	33	266	(55)	410
Long-term assets of discontinued operations	—	302	—	2,076	—	2,378
Total other assets	8,323	3,326	3,316	4,506	(14,031)	5,440
Total Assets	$10,062	$8,418	$3,370	$11,515	$(16,145)	$17,220

	December 31, 2002					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
LIABILITIES AND STOCKHOLDERS' EQUITY						
Current Liabilities:						
Current portion of long-term debt and short-term borrowings	$ 350	$ 7	$ 8	$ 455	$ —	$ 820
Accounts payable, principally trade	72	546	—	137	—	755
Accounts and notes payable — affiliated companies	—	1,192	7	921	(2,120)	—
Trading and derivative liabilities	—	407	—	110	—	517
Other current liabilities	26	312	13	119	(39)	431
Current liabilities of discontinued operations	—	4	—	1,084	—	1,088
Total current liabilities	448	2,468	28	2,826	(2,159)	3,611
Other Liabilities:						
Notes payable — affiliated companies	—	2,962	—	2,035	(4,997)	—
Trading and derivative liabilities	—	176	—	84	—	260
Accrual for payment to CenterPoint Energy, Inc.	—	128	—	—	—	128
Other long-term liabilities	45	162	4	643	(55)	799
Long-term liabilities of discontinued operations	—	12	—	748	—	760
Total other liabilities	45	3,440	4	3,510	(5,052)	1,947
Long-term Debt	3,916	4	466	1,623	—	6,009
Commitments and Contingencies						
Stockholders' Equity	5,653	2,506	2,872	3,556	(8,934)	5,653
Total Liabilities and Stockholders' Equity	$10,062	$8,418	$3,370	$11,515	$(16,145)	$17,220

	December 31, 2003					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
ASSETS						
Current Assets:						
Cash and cash equivalents	$ 23	$ 64	$ 10	$ 50	$ —	$ 147
Restricted cash	7	—	23	221	—	251
Accounts and notes receivable, principally customer, net	83	933	22	157	—	1,195
Accounts and notes receivable — affiliated companies	421	546	—	257	(1,224)	—
Inventory	—	109	—	160	—	269
Trading and derivative assets	—	372	—	121	—	493
Other current assets	8	218	3	105	—	334
Total current assets	542	2,242	58	1,071	(1,224)	2,689
Property, plant and equipment, gross	—	3,943	1	5,307	—	9,251
Accumulated depreciation	—	(348)	—	(376)	—	(724)
Property, Plant and Equipment, net	—	3,595	1	4,931	—	8,527
Other Assets:						
Goodwill, net(2)	—	84	—	399	—	483
Other intangibles, net	—	127	—	592	—	719
Notes receivable — affiliated companies	1,960	685	—	44	(2,689)	—
Equity investments	—	95	—	—	—	95
Equity investments in consolidated subsidiaries	5,178	275	2,821	—	(8,274)	—
Trading and derivative assets	3	170	—	27	—	200
Restricted cash	—	—	—	37	—	37
Other long-term assets	139	139	26	279	(25)	558
Total other assets	7,280	1,575	2,847	1,378	(10,988)	2,092
Total Assets	$7,822	$7,412	$2,906	$7,380	$(12,212)	$13,308

	December 31, 2003					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
LIABILITIES AND STOCKHOLDERS' EQUITY						
Current Liabilities:						
Current portion of long-term debt and short-term borrowings	$ (2)	$ 4	$ 8	$ 421	$ —	$ 431
Accounts payable, principally trade	5	444	—	68	—	517
Accounts and notes payable — affiliated companies	—	604	8	656	(1,268)	—
Trading and derivative liabilities	—	236	—	121	—	357
Accrual for payment to CenterPoint Energy, Inc.	—	175	—	—	—	175
Other current liabilities	76	367	13	62	—	518
Total current liabilities	79	1,830	29	1,328	(1,268)	1,998
Other Liabilities:						
Notes payable — affiliated companies	—	1,970	—	675	(2,645)	—
Trading and derivative liabilities	—	152	—	64	—	216
Other long-term liabilities	33	297	4	704	(25)	1,013
Total other liabilities	33	2,419	4	1,443	(2,670)	1,229
Long-term Debt	3,338	400	458	1,513	—	5,709
Commitments and Contingencies						
Stockholders' Equity	4,372	2,763	2,415	3,096	(8,274)	4,372
Total Liabilities and Stockholders' Equity	$7,822	$7,412	$2,906	$7,380	$(12,212)	$13,308

(1) These amounts relate to either (a) eliminations and adjustments recorded in the normal consolidation process or (b) reclassifications recorded due to differences in classifications at the subsidiary levels compared to the consolidated level.

(2) See subfootnote (2) in the 2003 statement of operations table above.

Condensed Consolidating Statements of Cash Flows.

	Year Ended December 31, 2001				
	Reliant Resources	Guarantors	Non-Guarantors	Adjustments(1)	Consolidated
			(In millions)		
Cash Flows from Operating Activities:					
Net cash provided by (used in) continuing operations from operating activities	$ 62	$224	$(242)	$ —	$ 44
Net cash used in discontinued operations from operating activities	—	(138)	(58)	—	(196)
Net cash provided by (used in) operating activities	62	86	(300)	—	(152)
Cash Flows from Investing Activities:					
Capital expenditures	(44)	(548)	(136)	—	(728)
Investments in and distributions from subsidiaries, net and Reliant Resources' advances to its wholly-owned subsidiaries, net(2)	(1,151)	3	—	1,148	—
Other, net	—	2	—	—	2
Net cash used in continuing operations from investing activities	(1,195)	(543)	(136)	1,148	(726)
Net cash used in discontinued operations from investing activities	—	(91)	(21)	—	(112)
Net cash used in investing activities	(1,195)	(634)	(157)	1,148	(838)
Cash Flows from Financing Activities:					
Proceeds from issuance of stock	1,696	—	—	—	1,696
Increase in short-term borrowings, net	—	—	129	—	129
Changes in notes with affiliated companies, net(3)	(382)	586	212	(1,148)	(732)
Purchase of treasury stock	(189)	—	—	—	(189)
Contributions from CenterPoint	9	—	—	—	9
Payments of financing costs	—	—	(1)	—	(1)
Other, net	—	3	—	—	3
Net cash provided by continuing operations from financing activities	1,134	589	340	(1,148)	915
Net cash provided by discontinued operations from financing activities	—	—	85	—	85
Net cash provided by financing activities	1,134	589	425	(1,148)	1,000
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	(6)	—	(6)
Net Change in Cash and Cash Equivalents	1	41	(38)	—	4
Cash and Cash Equivalents at Beginning of Period	—	27	67	—	94
Cash and Cash Equivalents at End of Period	$ 1	$ 68	$ 29	$ —	$ 98

	Year Ended December 31, 2002					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
Cash Flows from Operating Activities:						
Net cash (used in) provided by continuing operations from operating activities	$ (39)	$ 30	$(41)	$593	$ —	$ 543
Net cash (used in) provided by discontinued operations from operating activities	(116)	58	—	34	—	(24)
Net cash (used in) provided by operating activities	(155)	88	(41)	627	—	519
Cash Flows from Investing Activities:						
Capital expenditures	(76)	(347)	—	(217)	—	(640)
Business acquisition, net of cash acquired	(2,964)	—	76	—	(76)	(2,964)
Investments in and distributions from subsidiaries, net and Reliant Resources' and Orion Power Holdings' advances to and distributions from its wholly-owned subsidiaries, net(2)	(795)	(47)	171	180	491	—
Other, net	—	(1)	—	—	—	(1)
Net cash (used in) provided by continuing operations from investing activities	(3,835)	(395)	247	(37)	415	(3,605)
Net cash (used in) provided by discontinued operations from investing activities	—	(1)	—	120	—	119
Net cash (used in) provided by investing activities	(3,835)	(396)	247	83	415	(3,486)

	Year Ended December 31, 2002					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
Cash Flows from Financing Activities:						
Proceeds from long-term debt	—	13	—	—	—	13
Payments of long-term debt	—	(4)	(200)	—	—	(204)
Increase (decrease) in short-term borrowings, net	4,266	1	—	(201)	—	4,066
Changes in notes with affiliated companies, net(3)	382	633	—	(214)	(415)	386
Payments of financing costs	(16)	—	—	(27)	—	(43)
Proceeds from issuances of treasury stock	14	—	—	—	—	14
Other, net	—	—	—	(1)	—	(1)
Net cash provided by (used in) continuing operations from financing activities	4,646	643	(200)	(443)	(415)	4,231
Net cash used in discontinued operations from financing activities	—	—	—	(250)	—	(250)
Net cash provided by (used in) financing activities	4,646	643	(200)	(693)	(415)	3,981
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	—	3	—	3
Net Change in Cash and Cash Equivalents	656	335	6	20	—	1,017
Cash and Cash Equivalents at Beginning of Period	1	68	—	29	—	98
Cash and Cash Equivalents at End of Period	$ 657	$ 403	$ 6	$ 49	$ —	$ 1,115

	Year Ended December 31, 2003					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
Cash Flows from Operating Activities:						
Net cash (used in) provided by continuing operations from operating activities	$ (4)	$ 740	$24	$ 82	$ —	$ 842
Net cash (used in) provided by discontinued operations from operating activities	(26)	12	—	41	—	27
Net cash (used in) provided by operating activities	(30)	752	24	123	—	869
Cash Flows from Investing Activities:						
Capital expenditures	(21)	(467)	—	(99)	—	(587)
Investments in and distributions from subsidiaries, net and Reliant Resources' and Orion Power Holdings' advances to and distributions from its wholly-owned subsidiaries, net(2)	1,635	—	18	17	(1,670)	—
Purchase and sale of permits and licenses to affiliates	—	(19)	—	19	—	—
Other	—	5	—	3	—	8
Net cash provided by (used in) continuing operations from investing activities	1,614	(481)	18	(60)	(1,670)	(579)
Net cash provided by discontinued operations from investing activities	—	284	—	1,337	—	1,621
Net cash provided by (used in) investing activities	1,614	(197)	18	1,277	(1,670)	1,042

	Year Ended December 31, 2003					
	Reliant Resources	Guarantors	Orion Power Holdings	Non-Guarantors	Adjustments(1)	Consolidated
	(In millions)					
Cash Flows from Financing Activities:						
Proceeds from long-term debt	1,375	195	—	42	—	1,612
Payments of long-term debt	(2,048)	(5)	—	(112)	—	(2,165)
Decrease in short-term borrowings, net	(1,370)	—	—	(55)	—	(1,425)
Proceeds from issuances of treasury stock	8	—	—	—	—	8
Changes in notes with affiliated companies, net(3)	—	(1,084)	(38)	(548)	1,670	—
Payments of financing	(183)	—	—	(1)	—	(184)
Net cash used in continuing operations from financing activities	(2,218)	(894)	(38)	(674)	1,670	(2,154)
Net cash used in discontinued operations from financing activities	—	—	—	(734)	—	(734)
Net cash used in financing activities	(2,218)	(894)	(38)	(1,408)	1,670	(2,888)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	—	9	—	9
Net Change in Cash and Cash Equivalents	(634)	(339)	4	1	—	(968)
Cash and Cash Equivalents at Beginning of Period	657	403	6	49	—	1,115
Cash and Cash Equivalents at End of Period	$ 23	$ 64	$10	$ 50	$ —	$ 147

(1) These amounts relate to either (a) eliminations and adjustments recorded in the normal consolidation process or (b) reclassifications recorded due to differences in classifications at the subsidiary levels compared to the consolidated level.

(2) Investments in and distributions from subsidiaries, net and Reliant Resources' and Orion Power Holdings' advances to and distributions from its wholly-owned subsidiaries, net are classified as investing activities for Reliant Resources and its wholly-owned subsidiaries.

(3) Changes in notes with affiliated companies, net are classified as financing activities for Reliant Resources' wholly-owned subsidiaries.

(20) Unaudited Quarterly Information

	Year Ended December 31, 2002			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions)			
Revenues	$1,591	$2,055	$5,066	$1,876
Trading margins	51	115	115	7
Total revenues	1,642	2,170	5,181	1,883
Operating income (loss)	135	216	278	(166)
Income (loss) from continuing operations before income taxes	115	174	199	(259)
Income (loss) from continuing operations	74	117	108	(176)
Income (loss) from discontinued operations, net of tax	22	59	(58)	(472)
Income (loss) before cumulative effect of accounting change	96	176	50	(648)
Cumulative effect of accounting change, net of tax	(234)	—	—	—
Net (loss) income	(138)	176	50	(648)
Basic Earnings (Loss) Per Share:				
Income (loss) from continuing operations	$ 0.25	$ 0.41	$ 0.37	$(0.60)
Income (loss) from discontinued operations, net of tax	0.08	0.20	(0.20)	(1.63)
Income (loss) before cumulative effect of accounting change	0.33	0.61	0.17	(2.23)
Cumulative effect of accounting change, net of tax	(0.81)	—	—	—
Net (loss) income	$(0.48)	$ 0.61	$ 0.17	$(2.23)
Diluted Earnings (Loss) Per Share:				
Income (loss) from continuing operations	$ 0.25	$ 0.40	$ 0.37	$(0.60)
Income (loss) from discontinued operations, net of tax	0.08	0.20	(0.20)	(1.63)
Income (loss) before cumulative effect of accounting change	0.33	0.60	0.17	(2.23)
Cumulative effect of accounting change, net of tax	(0.81)	—	—	—
Net (loss) income	$(0.48)	$ 0.60	$ 0.17	$(2.23)

	Year Ended December 31, 2003			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions)			
Revenues	$2,645	$ 2,814	$3,747	$1,843
Trading margins	(83)	12	26	(4)
Total revenues	2,562	2,826	3,773	1,839
Operating income (loss)	11	70	(508)	114
Loss from continuing operations before income taxes	(75)	(43)	(658)	(46)
Loss from continuing operations	(52)	(31)	(791)	(28)
(Loss) income from discontinued operations, net of tax	(375)	24	(125)	60
Loss before cumulative effect of accounting changes	(427)	(7)	(916)	32
Cumulative effect of accounting changes, net of tax	(25)	1	—	—
Net loss	(452)	(6)	(916)	32
Basic Earnings (Loss) Per Share:				
Loss from continuing operations	$(0.18)	$ (0.10)	$(2.69)	$(0.10)
(Loss) income from discontinued operations, net of tax	(1.29)	0.08	(0.42)	0.21
Loss before cumulative effect of accounting changes	(1.47)	(0.02)	(3.11)	0.11
Cumulative effect of accounting changes, net of tax	(0.08)	—	—	—
Net loss	$(1.55)	$ (0.02)	$(3.11)	$ 0.11
Diluted Earnings (Loss) Per Share:				
Loss from continuing operations	$(0.18)	$ (0.10)	$(2.69)	$(0.10)
(Loss) income from discontinued operations, net of tax	(1.29)	0.08	(0.42)	0.21
Loss before cumulative effect of accounting changes	(1.47)	(0.02)	(3.11)	0.11
Cumulative effect of accounting changes, net of tax	(0.08)	—	—	—
Net loss	$(1.55)	$ (0.02)	$(3.11)	$ 0.11

The quarterly operating results incorporate the results of operations of Orion Power from our February 2002 acquisition date as discussed in note 5. The variances in revenues from quarter to quarter for 2002 and 2003 were primarily due to (a) the Orion Power acquisition (for 2002 only), (b) the seasonal fluctuations in demand for electric energy and energy services, (c) changes in energy commodity prices and (d) implementation of EITF No. 02-03 (2002 only) and EITF No. 03-11 (2003 only) (see

notes 2(d) and 7). Changes in operating income (loss) and net income (loss) from quarter to quarter for 2002 and 2003 were primarily due to:

- the seasonal fluctuations in demand for electric energy and energy services;
- changes in energy commodity prices;
- the timing of maintenance expenses on electric generation plants; and
- provisions and reversals related to energy sales and refunds in California.

In addition, operating income (loss) and net income (loss) changed from quarter to quarter in 2002 by:

- the impact of the Orion Power acquisition (see note 5);
- $109 million in pre-tax loss related to changes in our estimated refund obligation, credit reserve and interest receivable for energy sales in California ($33 million in income in the first quarter, $29 million in loss in the second quarter, $15 million in loss in the third quarter and $98 million in loss in the fourth quarter) (see note 15(b));
- $234 million, net of tax, cumulative effect of an accounting change related to the adoption of SFAS No. 142 in the first quarter of 2002 for our discontinued European energy operations (only impacted net loss) (see note 6);
- a one-time $109 million pre-tax gain resulting from the amendment of certain contracts in our European energy discontinued operations in the second quarter of 2002 (only impacted net income);
- costs related to plant cancellations and equipment impairments in the second and third quarters of 2002;
- $128 million accrual recorded in the third and fourth quarters of 2002 for a payment to CenterPoint (see note 14(d));
- $47 million pre-tax, non-cash charge in the third quarter of 2002 relating to the accounting settlement of certain benefit obligations associated with our separation from CenterPoint (see note 12);
- $45 million tax accrual related to our European energy discontinued operations in the third quarter of 2002 (only impacted net income);
- $482 million goodwill impairment in our European energy discontinued operations in the fourth quarter of 2002 (only impacted net loss) (see note 6);
- impairment charges of $32 million pre-tax relating to certain cost method investments ($27 million pre-tax in the fourth quarter) in 2002 (see note 2(o)); and
- $14 million provision for a FERC settlement in January 2003, which was recorded in the fourth quarter of 2002 (see note (15(a)).

Also, operating income (loss) and net income (loss) changed from quarter to quarter in 2003 by:

- $108 million in pre-tax income related to changes in our estimated refund obligation, credit reserve and interest receivable for energy sales in California ($84 million in income in the first quarter, $1 million in income in the second quarter and $23 million in income in the fourth quarter) (see note 15(b));

- $310 million loss on the disposition of our discontinued European energy operations ($384 million loss in the first quarter, $44 million gain in the second quarter, $53 million loss in the third quarter and $83 million gain in the fourth quarter) (only impacted net loss) (see note 22);
- $80 million pre-tax trading loss related to certain of our natural gas trading positions recognized in the first quarter of 2003;
- $47 million accrual for a payment to CenterPoint in the first quarter of 2003 (see note 14(d));
- $24 million, net of tax, cumulative effect of accounting changes primarily in the first quarter of 2003 (only impacted net loss) (see notes 2(c), 2(d) and 2(q));
- $985 million goodwill impairment in our wholesale energy segment in the third quarter of 2003 (see note 6);
- $75 million loss on the disposition of our Desert Basin plant operations in the third quarter of 2003 (see note 23);
- $37 million provision for a settlement agreement reached with the FERC in the third quarter of 2003 (see note 15(a));
- $28 million write-off of deferred financing costs in the third quarter of 2003 (see note 2(r));
- $14 million increase in depreciation expense associated with the early retirements of several units in the third quarter of 2003;
- $27 million write-off of deferred financing costs in the fourth quarter of 2003 (see note 2(r)); and
- $18 million provision for the CFTC settlement in the fourth quarter of 2003 (see note 15(a)).

(21) Reportable Segments

We have identified the following reportable segments: retail energy, wholesale energy and other operations. The accounting policies of our reportable segments are the same as those described in the summary of significant accounting policies (note 2). We account for intersegment revenues as if such revenues were to third parties, that is, at current market prices or pursuant to intercompany agreements entered into at current market prices. In December 2003, we sold our European energy operations and have classified that as discontinued operations (see note 22). In October 2003, we sold our Desert Basin plant operations (which was formerly included in our wholesale energy segment) and have classified that as discontinued operations (see note 23). Our determination of reportable segments considers the strategic operating units under which we manage sales, allocate resources and assess performance of various products and services to wholesale or retail customers. Earnings (loss) before interest expense, interest income and income taxes (EBIT) is the primary measurement used by our management to evaluate the performance of each of our business segments. EBIT is not defined under GAAP, should not be considered in isolation or as a substitute for a measure of performance prepared in accordance with GAAP and is not indicative of operating income (loss) from operations as determined under GAAP.

As part of our review of the organization of our business units, effective December 31, 2003, we began reporting our ERCOT generation facilities, which consist of ten power generation units completed or under various stages of construction at seven facilities with an aggregate net generation capacity of 805 MW located in Texas, in our wholesale energy segment rather than our retail energy segment. Reportable segments from prior periods have been reclassified to conform to the 2003 presentation.

Long-lived assets include net property, plant and equipment, net goodwill, net other intangibles and equity investments.

Financial data for business segments (excluding items related to our discontinued operations, other than total assets) are as follows:

	Retail Energy	Wholesale Energy	Other Operations	Discontinued Operations	Eliminations	Consolidated
				(In millions)		
For the year ended December 31, 2001 (except as denoted):						
Revenues from external customers	$ 114	$5,374	$ 11	$ —	$ —	$5,499
Trading margins	74	304	—	—	—	378
Depreciation and amortization	11	117	42	—	—	170
Operating (loss) income	(13)	904	(190)	—	—	701
Income of equity investments	—	7	—	—	—	7
EBIT	(13)	913	(167)	—	—	733
Expenditures for long-lived assets	117	567	44	—	—	728
Equity investments as of December 31, 2001	—	88	—	—	—	88
Total assets as of December 31, 2001	391	7,350	645	3,670	(330)	11,726
For the year ended December 31, 2002 (except as denoted):						
Revenues from external customers	4,200	6,385	3	—	—	10,588
Intersegment revenues	2	64	—	—	(66)	—
Trading margins	152	136	—	—	—	288
Depreciation and amortization	26	327	15	—	—	368
Operating income (loss)	530	(3)	(64)	—	—	463
Income of equity investments	—	18	—	—	—	18
EBIT	520	30	(87)	—	—	463
Expenditures for long-lived assets	33	3,494	77	—	—	3,604
Equity investments as of December 31, 2002	—	103	—	—	—	103
Total assets as of December 31, 2002	1,422	12,168	916	3,042	(328)	17,220
For the year ended December 31, 2003 (except as denoted):						
Revenues from external customers	5,936	5,112	1	—	—	11,049
Intersegment revenues	—	234	—	—	(234)	—
Trading margins	—	(49)	—	—	—	(49)
Depreciation and amortization	35	353	31	—	—	419
Operating income (loss)	658	(941)	(30)	—	—	(313)
Loss of equity investments	—	(2)	—	—	—	(2)
EBIT	621	(934)	(28)	—	—	(341)
Expenditures for long-lived assets	23	521	43	—	—	587
Equity investments as of December 31, 2003	—	95	—	—	—	95
Total assets as of December 31, 2003	1,162	11,767	555	—	(176)	13,308

	As of and for the Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Reconciliation of Operating Income (Loss) to EBIT and EBIT to Net Income (Loss):			
Operating income (loss)	$ 701	$ 463	$ (313)
Gains (losses) from investments, net	23	(23)	2
Income of equity investments	7	18	(2)
Loss on sale of receivables	—	(10)	(37)
Other income, net	2	15	9
EBIT	733	463	(341)
Interest expense	(16)	(267)	(516)
Interest income	22	28	35
Interest income — affiliated companies, net	12	5	—
Income (loss) from continuing operations before income taxes	751	229	(822)
Income tax expense	290	106	80
Income (loss) from continuing operations	461	123	(902)
Income (loss) from discontinued operations	99	(449)	(416)
Income (loss) before cumulative effect of accounting changes	560	(326)	(1,318)
Cumulative effect of accounting changes, net of tax	3	(234)	(24)
Net income (loss)	$ 563	$ (560)	$(1,342)
Revenues by Products and Services:			
Retail energy products and services	$ 114	$ 4,202	$ 5,936
Wholesale energy and energy related sales	5,374	6,449	5,346
Energy trading margins	378	288	(49)
Other	11	3	1
Eliminations	—	(66)	(234)
Total	$5,877	$10,876	$11,000
Revenues and Long-Lived Assets by Geographic Areas:			
Revenues:			
United States(1)	$5,900	$10,871	$11,011
Canada(2)	(23)	5	(11)
Total	$5,877	$10,876	$11,000
Long-lived assets:			
United States	$3,416	$ 9,372	$ 9,824
Total	$3,416	$ 9,372	$ 9,824

(1) For 2001, 2002 and 2003, revenues include trading margins of $401 million, $283 million and $(38) million, respectively.

(2) For 2001, 2002 and 2003, revenues include trading margins of $(23) million, $5 million and $(11) million, respectively.

(22) Discontinued Operations — Sale of Our European Energy Operations

General. In February 2003, we signed an agreement to sell our European energy operations through the sale of our shares in RE BV, a holding company for these operations. The sale closed in December 2003.

We calculated the United States dollar amounts, for those items disclosed as of either December 31, 2002 or 2003, assuming an exchange rate of 1.2595 US dollar to the Euro for December 31, 2003, and an exchange rate of 1.0492 US dollar to the Euro for December 31, 2002, unless the context indicates otherwise.

Purchase Price. We received net cash proceeds of $1.4 billion (Euro 1.1 billion). We used the net cash proceeds from the sale (a) to prepay the Euro 600 million bank term loan borrowed by RECE to finance a portion of the original acquisition costs of our European energy operations and (b) to prepay $567 million of debt under our March 2003 credit facilities ($360 million, which had been temporarily placed in an escrow account, and an additional $207 million from the remaining net proceeds).

As additional contingent consideration for the sale, we are also entitled to receive from the purchaser 90% of any cash payments in excess of $139 million (Euro 110 million) paid by NEA B.V. (NEA) after February 2003, to Reliant Energy Power Generation Benelux B.V. (REPGB), the operating subsidiary of RE BV. REPGB has an equity investment in NEA, the former coordinating body for the Dutch electricity sector. NEA is in the process of liquidating various stranded cost contract liabilities incurred by it during the period prior to the liberalization of the Dutch energy market. Given uncertainties associated with this liquidation, there can be no assurance as to the amount, if any, or timing of potential consideration resulting from cash payments by NEA. As of December 31, 2003, we have no asset recorded in our consolidated balance sheet for these potential cash payments from NEA.

Accounting Treatment of Sale Transaction. In connection with the sale, we recognized a loss on disposition of $310 million during 2003. We do not currently anticipate that there will be a Dutch or United States income tax benefit realized by us as a result of this loss. We will recognize contingent payments, if any (as discussed above), in earnings upon receipt. During the first quarter of 2003, we began to report the results of our European energy operations as discontinued operations in accordance with SFAS No. 144 and accordingly, reclassified amounts from prior periods. For information regarding goodwill impairments of our European energy segment recognized in the first and fourth quarters of 2002 of $234 million and $482 million, respectively, see note 6.

Assets and liabilities related to our European energy discontinued operations were as follows as of December 31, 2002 (in millions):

Current Assets:	
Cash and cash equivalents	$ 112
Accounts and notes receivable and accrued unbilled revenues, principally customer, net	377
Other current assets	164
Total current assets	653
Property, Plant and Equipment, net	1,647
Other Assets:	
Stranded costs indemnification receivable	203
Investment in NEA	210
Other	16
Total long-term assets	2,076
Total Assets	$2,729
Current Liabilities:	
Current portion of long-term debt and short-term borrowings	$ 631
Accounts payable, principally trade	306
Other current liabilities	147
Total current liabilities	1,084
Other Liabilities:	
Trading and derivative liabilities, including stranded costs liability	363
Other liabilities	348
Total other liabilities	711
Long-term Debt	37
Total long-term liabilities	748
Total Liabilities	$1,832
Accumulated other comprehensive income	$ 39

Revenues and pre-tax income (loss) related to our European energy discontinued operations were as follows:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Revenues	$614	$632	$ 658
Income (loss) before income tax expense/benefit	79	(380)	(253) (1)

(1) Included in this amount is a $310 million loss related to our loss on disposition.

(23) Discontinued Operations — Sale of Our Desert Basin Plant Operations

On July 9, 2003, we entered into a definitive agreement to sell our 588-megawatt Desert Basin plant, located in Casa Grande, Arizona, to Salt River Project Agricultural Improvement and Power District (SRP) of Phoenix for $289 million. The sale closed in October 2003. Desert Basin, a combined-cycle facility that we developed, started commercial operation in 2001 and provided all of its power to SRP under a 10-year power purchase agreement, which terminated in connection with the sale. The Desert Basin plant was the only operation of Reliant Energy Desert Basin, LLC, a subsidiary of Reliant Resources. We used the net proceeds from the sale of $285 million to prepay indebtedness under our March 2003 credit facilities.

During the third quarter of 2003, we began to report the results of our Desert Basin plant operations as discontinued operations in accordance with SFAS No. 144 and accordingly, reclassified amounts from prior periods. We recognized a loss of $75 million, after-tax, on the disposition of our Desert Basin plant operations during 2003. The loss on disposition of $84 million ($75 million after-tax), consisted of a loss of $21 million ($12 million after-tax) on the tangible assets and liabilities associated with our actual investment in the Desert Basin plant operations and a loss of $63 million (pre-tax and after-tax) relating to the allocated goodwill of our wholesale energy reporting unit. We did not allocate any goodwill to our Desert Basin plant operations prior to July 2003.

Assets and liabilities related to our Desert Basin plant discontinued operations were as follows as of December 31, 2002 (in millions):

Current Assets:	
Cash and cash equivalents	$ —
Accounts and notes receivable and accrued unbilled revenues, principally customer, net	6
Other current assets	5
Total current assets	11
Property, Plant and Equipment, net	302
Other Assets:	
Other	—
Total long-term assets	302
Total Assets	$313
Current Liabilities:	
Accounts payable, principally trade	$ 1
Other current liabilities	3
Total current liabilities	4
Other Liabilities:	
Other liabilities	12
Total other liabilities	12
Total long-term liabilities	12
Total Liabilities	$ 16

Revenues and pre-tax income (loss) related to our Desert Basin plant discontinued operations were as follows:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Revenues	$8	$62	$49
Income (loss) before income tax expense/benefit	4	39	(57) (1)

(1) Included in this amount is an $84 million loss related to our loss on disposition.

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RELIANT RESOURCES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF OPERATIONS
(Thousands of Dollars)

	Year Ended December 31,		
	2001	2002	2003
(Expenses) Income:			
General, administrative and depreciation, net	$(104,382)	$ (53,596)	$ (10,630)
Equity in earnings (loss) of investments in subsidiaries	567,032	(523,524)	(1,176,905)
Foreign currency translation loss from intercompany note receivable	(15,839)	—	—
Transaction costs associated with sale of European energy operations	—	—	(15,647)
Interest expense	(9,625)	(116,197)	(379,193)
Interest income	—	8,628	3,666
Interest income — CenterPoint, net	2,523	2,657	—
Interest income — subsidiaries, net	126,576	103,322	168,668
Income (Loss) Before Income Taxes	566,285	(578,710)	(1,410,041)
Income tax expense (benefit)	2,934	(18,898)	(67,924)
Net Income (Loss)	$ 563,351	$(559,812)	$(1,342,117)

See Notes to the Condensed Financial Statements and Reliant Resources' Consolidated Financial Statements

RELIANT RESOURCES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(Thousands of Dollars)

	December 31,	
	2002	2003
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 656,966	$ 23,435
Restricted cash	—	7,000
Advances to and notes receivable from subsidiaries, net	817,128	420,546
Accounts and notes receivable from CenterPoint, net	25,887	—
Federal income tax receivable	94,792	83,310
Accumulated deferred income taxes	17,585	8,253
Prepayments and other current assets	5,161	—
Total current assets	1,617,519	542,544
Property, Plant and Equipment, net	120,893	—
Other Assets:		
Advances to and notes receivable from subsidiaries, net	2,539,275	1,959,904
Investments in subsidiaries	5,714,872	5,177,690
Accumulated deferred income taxes	25,822	—
Restricted cash	7,000	—
Other	36,512	142,279
Total other assets	8,323,481	7,279,873
Total Assets	$10,061,893	$7,822,417
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 350,000	$ (2,251)
Accounts and other payables	72,467	5,050
State franchise tax payable	20	4,446
Interest payable	17,024	57,047
Other	8,806	15,444
Total current liabilities	448,317	79,736
Benefit Obligations and Other Liabilities	44,688	33,037
Long-term Debt	3,916,000	3,337,845
Commitments and Contingencies (note 5)		
Stockholders' Equity:		
Preferred stock; par value $0.001 per share (125,000,000 shares authorized; none outstanding)	—	—
Common stock; par value $0.001 per share (2,000,000,000 shares authorized; 299,804,000 issued)	61	61
Additional paid-in capital	5,836,957	5,841,438
Treasury stock at cost 9,198,766 and 5,212,017 shares	(158,483)	(89,769)
Retained earnings (deficit)	3,539	(1,338,578)
Accumulated other comprehensive loss	(29,186)	(41,353)
Stockholders' equity	5,652,888	4,371,799
Total Liabilities and Stockholders' Equity	$10,061,893	$7,822,417

See Notes to the Condensed Financial Statements and Reliant Resources' Consolidated Financial Statements

RELIANT RESOURCES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS
(Thousands of Dollars)

	Year Ended December 31,		
	2001	2002	2003
Cash Flows from Operating Activities:			
Net income (loss)	$ 563,351	$ (559,812)	$(1,342,117)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Deferred income taxes	(39,840)	35,862	(11,919)
Equity in (earnings) loss of investment in subsidiaries	(567,032)	523,524	1,176,905
Curtailment and related benefit enhancement	99,523	—	—
Accounting settlement for certain benefit plans	—	47,356	—
Ineffectiveness of interest rate hedges	—	16,037	10,618
Amortization of deferred financing costs	591	1,330	94,787
Other, net	—	9,993	(16,460)
Changes in other assets and liabilities:			
Receivables from subsidiaries, net	(48,365)	(4,779)	19,993
Receivables from CenterPoint, net	(4,332)	1,196	25,887
Federal income tax receivable/payable	6,149	11,132	4,829
Other current assets	(1,141)	(4,020)	(5,139)
Other assets	(5,297)	(27,778)	(30,857)
Accounts and other payables	32,730	(5,073)	(560)
State franchise tax payable	—	20	4,426
Interest payable	—	17,024	40,023
Other current liabilities	20,120	340	19,963
Interest rate hedges	—	(55,048)	(29,469)
Hedges of net investment in foreign subsidiaries	—	(162,432)	(7,775)
Other liabilities	5,422	276	16,941
Net cash provided by (used in) operating activities	61,879	(154,852)	(29,924)
Cash Flows from Investing Activities:			
Capital expenditures	(44,278)	(76,238)	(20,116)
Business acquisition, net of cash acquired	—	(2,963,801)	—
Investments in, advances to and notes receivable from subsidiaries, net	(1,150,540)	(794,874)	1,634,946
Net cash (used in) provided by investing activities	(1,194,818)	(3,834,913)	1,614,830

RELIANT RESOURCES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS — (continued)
(Thousands of Dollars)

	Year Ended December 31,		
	2001	2002	2003
Cash Flows from Financing Activities:			
Proceeds from debt	—	—	1,375,000
Payments of long-term debt	—	—	(2,047,878)
Proceeds from issuance of stock, net	1,696,074	—	—
Increase (decrease) in short-term borrowings and revolving credit facilities, net	—	4,266,000	(1,369,814)
Purchase of treasury stock	(189,460)	—	—
Proceeds from issuances of treasury stock	—	13,527	7,531
Payments of financing costs	—	(15,978)	(183,276)
Change in notes receivable with CenterPoint, net	(381,854)	381,854	—
Contributions from CenterPoint	9,441	—	—
Other, net	—	66	—
Net cash provided by (used in) financing activities	1,134,201	4,645,469	(2,218,437)
Net Change in Cash and Cash Equivalents	1,262	655,704	(633,531)
Cash and Cash Equivalents at Beginning of Year	—	1,262	656,966
Cash and Cash Equivalents at End of Year	$ 1,262	$ 656,966	$ 23,435
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest paid	$ 11,150	$ 84,267	$ 228,182
Income taxes paid (net of income tax refunds received)	32,729	(32,737)	(47,966)

See Notes to the Condensed Financial Statements and Reliant Resources' Consolidated Financial Statements

RELIANT RESOURCES, INC.

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT

NOTES TO CONDENSED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

These condensed parent company financial statements have been prepared in accordance with Rule 12-04, Schedule 1 of Regulation S-X, as the restricted net assets of Reliant Resources' subsidiaries exceed 25% of the consolidated net assets of Reliant Resources. This information should be read in conjunction with the Reliant Resources and subsidiaries consolidated financial statements included elsewhere in this filing.

Reliant Resources, a Delaware corporation, was incorporated in August 2000 with 1,000 shares of common stock, which were owned by Reliant Energy. Effective December 31, 2000, Reliant Energy consolidated its unregulated operations under Reliant Resources. In addition, corporate support and executive officers transferred to Reliant Resources on January 1, 2001.

Effective July 1, 2003, we formed a new company, Reliant Energy Corporate Services, LLC (RECS), which is wholly-owned by Reliant Resources. RECS was created to hold the employees, the employee-related costs and other general corporate activities that were previously held by Reliant Resources. The applicable assets and liabilities were transferred from Reliant Resources to RECS effective July 1, 2003.

Reliant Resources' 100% investments in its subsidiaries have been recorded using the equity basis of accounting in the accompanying condensed parent company financial statements. Included in equity in earnings (loss) of investments in subsidiaries in 2001, 2002 and 2003 are (a) earnings/losses related to our European energy operations, which have been reflected as discontinued operations as more fully described in note 22 to Reliant Resources' consolidated financial statements and (b) cumulative effects of accounting changes for new accounting pronouncements as more fully described in notes 2(c), 2(d), 2(q) and 6 to Reliant Resources' consolidated financial statements.

Some amounts from the previous years have been reclassified to conform to the 2003 presentation of condensed financial information. These reclassifications do not affect earnings.

(2) Certain Related Party Transactions

(a) Income Taxes

Prior to October 1, 2002, Reliant Resources was included in the consolidated federal income tax returns of CenterPoint and calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint. Prior to October 1, 2002, current federal income taxes were payable to or receivable from CenterPoint. Subsequent to September 30, 2002, Reliant Resources files a separate federal income tax return. As of October 1, 2002, Reliant Resources entered into a tax sharing agreement with certain of its subsidiaries. Pursuant to the tax sharing agreement, Reliant Resources pays all federal income taxes on behalf of its subsidiaries included in the consolidated tax group and is entitled to any related tax refunds. The difference between Reliant Resources' current federal income tax expense or benefit, as calculated on a separate return basis, and related amounts payable to/receivable from the Internal Revenue Service is reflected as an increase/decrease to the investments in subsidiaries account and is reflected on the subsidiaries' books as adjustments to their equity. During 2002 and 2003, Reliant Resources made equity contributions to its subsidiaries for deemed distributions related to current federal income taxes of $64 million and $52 million, respectively.

(b) Allocations of General, Administrative and Depreciation Costs and Cash Management Function

Certain general, administrative and depreciation costs are allocated from Reliant Resources to its subsidiaries. For 2001, 2002 and 2003, these allocations were $136 million, $187 million and $110 million, respectively, and are netted in the applicable line on the condensed statements of operations. The unpaid

allocations are reflected as a component of current advances to and notes receivable from subsidiaries, net in the condensed balance sheets. As discussed in note 1, as certain assets and liabilities were transferred from Reliant Resources to RECS effective July 1, 2003, the related activity and costs from that date through December 31, 2003 were allocated from RECS to Reliant Resources' subsidiaries and are not reflected in the $110 million of allocations discussed above for 2003. The amount allocated from RECS to Reliant Resources' subsidiaries from July 1, 2003 through December 31, 2003, was $125 million.

Through June 30, 2002, a subsidiary of CenterPoint had established a "money fund" through which Reliant Resources could borrow or invest on a short-term basis. Also, during 2001, proceeds not utilized from the IPO were advanced to this subsidiary of CenterPoint. Reliant Resources earned interest income from CenterPoint for these short-term investments. After the IPO, Reliant Resource established a similar "money fund" or "central bank" through which its subsidiaries can borrow or invest on a short-term basis. The net amounts are included in current and long-term advances to and notes receivable from subsidiaries, net in the condensed balance sheets.

(3) Restricted Net Assets of Subsidiaries

Certain of Reliant Resources' subsidiaries have effective restrictions on their ability to pay dividends or make intercompany loans and advances pursuant to their financing arrangements. The amount of restricted net assets of Reliant Resources' subsidiaries as of December 31, 2003 is approximately $2.8 billion. Such restrictions are on the net assets of Orion Capital, Liberty and Channelview. Orion MidWest and Orion NY are subsidiaries of Orion Capital.

It is the customary practice of Reliant Resources to loan monies to and borrow monies from certain of its subsidiaries through the use of the "central bank" as described in note 2 above. However, there were no legally declared cash dividends or return of shareholder's equity to Reliant Resources from its subsidiaries in 2001, 2002 and 2003.

(4) Banking or Debt Facilities

For a discussion of Reliant Resources' banking or debt facilities, see note 9 to Reliant Resources' consolidated financial statements. Reliant Resources' debt obligations are included in the Other Operations segment data in note 21 to Reliant Resources' consolidated financial statements.

Maturities of Reliant Resources' debt obligations outstanding as of December 31, 2003, were as follows (in millions):

2004	$ —
2005	—
2006	—
2007	1,968
2008	—
2009 and thereafter	1,376
Subtotal	3,344
Other items included in debt	(8)
Total debt	$3,336

(5) Commitments and Contingencies

For a discussion of Reliant Resources' commitments and contingencies, see notes 14 and 15 to Reliant Resources' consolidated financial statements.

(a) Guarantees

Reliant Resources has issued guarantees in conjunction with certain performance agreements and commodity and derivative contracts and other contracts that provide financial assurance to third parties on behalf of a subsidiary or an unconsolidated third-party. The guarantees on behalf of subsidiaries are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the relevant subsidiary's intended commercial purposes.

The following tables detail Reliant Resources' various guarantees, including the maximum potential amounts of future payments, assets held as collateral and the carrying amount of the liabilities recorded on the balance sheets, if applicable:

	December 31, 2002		
Type of Guarantee	Maximum Potential Amount of Future Payments	Assets Held as Collateral	Carrying Amount of Liability Recorded on Balance Sheet
		(In millions)	
Trading and hedging obligations(1)	$5,012	$—	$—
Guarantees under construction agency agreements(2)	1,325	—	—
Payment and performance obligations under power purchase agreements for power generation assets and renewables(3)	339	—	—
Standby letters of credit(4)	72	—	—
Payment and performance obligations under service contracts and leases(5)	103	—	—
Non-qualified benefits of CenterPoint's retirees(6)	58	—	—
Sale of electricity to large commercial, industrial and institutional customers(7)	48	—	—
Total guarantees	$6,957	$—	$—

Type of Guarantee	December 31, 2003		
	Maximum Potential Amount of Future Payments	Assets Held as Collateral	Carrying Amount of Liability Recorded on Balance Sheet
		(In millions)	
Trading and hedging obligations(1)	$4,616	$—	$—
Payment and performance obligations under power purchase agreements for power generation assets and renewables(3)	326	—	—
Standby letters of credit(4)	166	—	—
Payment and performance obligations under service contracts and leases(5)	87	—	—
Non-qualified benefits of CenterPoint's retirees(6)	57	—	—
Sale of electricity to large commercial, industrial and institutional customers(7)	40	—	—
Total guarantees	$5,292	$—	$—

(1) Reliant Resources has guaranteed the performance of certain of its wholly-owned subsidiaries' trading and hedging obligations. These guarantees were provided to counterparties in order to facilitate physical and financial agreements in electricity, gas, oil, transportation and related commodities and services. These guarantees have varying expiration dates. The fair values of the underlying transactions are included in Reliant Resources' subsidiaries' balance sheets.

(2) See note 14(b) to Reliant Resources' consolidated financial statements for discussion of Reliant Resources' guarantees under the construction agency agreements. These guarantees were terminated in March 2003.

(3) Reliant Resources has guaranteed the payment and performance obligations of certain wholly-owned subsidiaries arising under certain power purchase agreements. As of December 31, 2003, these guarantees have varying expiration dates through December 2016.

(4) Reliant Resources has outstanding standby letters of credit which guarantee the performance of certain of its wholly-owned subsidiaries. As of December 31, 2003, these letters of credit expire on various dates through December 2004.

(5) Reliant Resources has guaranteed the payment obligations of certain wholly-owned subsidiaries arising under long-term service agreements and leases for certain facilities. As of December 31, 2003, the expiration of certain guarantees was not yet determinable. As of December 31, 2003, guarantees with determinable expiration dates expire over varying years through December 2019.

(6) Reliant Resources has guaranteed, in the event CenterPoint becomes insolvent, certain non-qualified benefits of CenterPoint's and its subsidiaries' existing retirees at the Distribution. See note 14(e) to Reliant Resources' consolidated financial statements.

(7) Reliant Resources has guaranteed commodity related payments for certain wholly-owned subsidiaries' sale of electricity to large commercial, industrial and institutional customers to facilitate the physical and financial transactions of electricity services. As of December 31, 2003, these guarantees expire on various dates through October 2006.

Unless otherwise noted, failure by the primary obligor to perform under the terms of the various agreements and contracts guaranteed may result in the beneficiary requesting immediate payment from Reliant Resources. To the extent liabilities exist under the various agreements and contracts that Reliant Resources guarantees, such liabilities are recorded in Reliant Resources' subsidiaries' balance sheets at December 31, 2003. Management believes the likelihood that Reliant Resources would be required to perform or otherwise incur any significant losses associated with any of these guarantees is remote.

Reliant Resources has entered into contracts that include indemnification and guarantee provisions as a routine part of its business activities. Examples of these contracts include asset purchase and sale agreements, commodity purchase and sale agreements, operating agreements, service agreements, lease agreements, procurement agreements and certain debt agreements. In general, these provisions indemnify

the counterparty for matters such as breaches of representations and warranties and covenants contained in the contract and/or against certain specified liabilities. In the case of commodity purchase and sale agreements, generally damages are limited through liquidated damages clauses whereby the parties agree to establish damages as the costs of covering any breached performance obligations. In the case of debt agreements, Reliant Resources generally indemnifies against liabilities that arise from the preparation, entry into, administration or enforcement of the agreement. Under these indemnifications and guarantees, the maximum potential amount is not estimable given that the magnitude of any claims under the indemnifications would be a function of the extent of damages actually incurred, which is not practicable to estimate unless and until the event occurs. Management believes the likelihood of making any material payments under these provisions is remote. For additional discussion of certain indemnifications and guarantees by Reliant Resources, see note 14(e) to Reliant Resources' consolidated financial statements.

(b) Leases

As of December 31, 2003, Reliant Resources is obligated under long-term non-cancelable operating leases, including the lease related to our corporate headquarters. The following table sets forth information concerning these cash obligations as of December 31, 2003 (in millions):

2004	$ 26
2005	22
2006	22
2007	22
2008	22
2009 and thereafter	217
Total	$331

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RELIANT RESOURCES, INC. AND SUBSIDIARIES

SCHEDULE II — RESERVES
For the Three Years Ended December 31, 2003
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts(1)	Deductions from Reserves(2)	Balance at End of Period
For the Year Ended December 31, 2001:					
Accumulated provisions:					
Uncollectible accounts receivable	$51,466	$38,230	$ 1,455	$(1,487)	$89,664
Reserves deducted from trading assets	66,132	27,717	—	—	93,849
Reserves for accrue-in-advance major maintenance	16,549	(11,870)	—	—	4,679
Reserves for inventory	6,828	51	—	(6,424)	455
Deferred tax assets valuation	10,631	(7,977)	—	—	2,654
For the Year Ended December 31, 2002:					
Accumulated provisions:					
Uncollectible accounts receivable	89,664	21,126	989	(43,494)	68,285
Reserves deducted from trading assets	93,849	(34,938)	—	(13,437)	45,474
Reserves for accrue-in-advance major maintenance	4,679	2,056	—	—	6,735
Reserves for inventory	455	725	208	—	1,388
Deferred tax assets valuation	2,654	15,957	29,714	—	48,325
For the Year Ended December 31, 2003:					
Accumulated provisions:					
Uncollectible accounts receivable	68,285	78,545	—	(72,789)	74,041
Reserves deducted from trading assets	45,474	(24,111)	(11,992)	—	9,371
Reserves for accrue-in-advance major maintenance	6,735	2,912	—	—	9,647
Reserves for inventory	1,388	(1,180)	—	—	208
Deferred tax assets valuation	48,325	214,812	—	—	263,137

(1) Charged to other accounts represents obligations acquired through business acquisitions and transfers of reserves to other accounts. In 2003, we changed our classification of certain derivative activities that historically were reclassified as trading activities to non-trading activities. See note 2(d) to Reliant Resources' consolidated financial statements.

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

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INDEX TO FINANCIAL STATEMENTS

RELIANT ENERGY RETAIL HOLDINGS, LLC AND SUBSIDIARIES

Independent Auditors' Report	F-118
Consolidated Statements of Operations for the Years Ended December 31, 2001, 2002 and 2003	F-119
Consolidated Balance Sheets as of December 31, 2002 and 2003	F-120
Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2002 and 2003	F-121
Consolidated Statements of Member's (Deficit) Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2001, 2002 and 2003	F-122
Notes to Consolidated Financial Statements	F-123

INDEPENDENT AUDITORS' REPORT

To the Management of Reliant Energy Retail Holdings, LLC
Houston, Texas

We have audited the accompanying consolidated balance sheets of Reliant Energy Retail Holdings, LLC and its subsidiaries (the Company), as of December 31, 2002 and 2003, and the related consolidated statements of operations, cash flows, member's (deficit) equity and comprehensive income (loss) for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in notes 2, 5 and 6 to the consolidated financial statements, the Company changed its accounting for energy trading contracts and its presentation of revenues and costs of sales associated with non-trading commodity derivative activities in 2003, its method of presenting its trading activities from a gross basis to a net basis and its accounting for goodwill and other intangibles in 2002.

DELOITTE & TOUCHE LLP

Houston, Texas
March 5, 2004

RELIANT ENERGY RETAIL HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2001	2002	2003
	(Thousands of dollars)		
Revenues:			
Electricity sales and service revenues	$113,601	$3,020,341	$5,059,616
Trading margins	74,354	157,940	—
Total	187,955	3,178,281	5,059,616
Expenses:			
Purchased power	4,757	2,037,428	3,845,375
Accrual for payment to CenterPoint Energy, Inc.	—	128,300	46,700
Operation and maintenance	109,947	153,068	175,957
General and administrative	75,095	232,721	277,616
Depreciation and amortization	10,843	26,061	35,911
Taxes other than income	543	59,122	61,205
Total	201,185	2,636,700	4,442,764
Operating (Loss) Income	(13,230)	541,581	616,852
Other (Expense) Income:			
Loss on sale of receivables	—	(10,347)	(37,613)
Other, net	49	42	103
Interest (expense) income — affiliated companies, net	(9,516)	896	17,869
Interest expense	(79)	(3,539)	(6,009)
Interest income	432	4,600	12,555
Total other expense	(9,114)	(8,348)	(13,095)
(Loss) Income Before Income Taxes	(22,344)	533,233	603,757
Income tax (benefit) expense	(7,562)	205,125	231,556
(Loss) Income Before Cumulative Effect of Accounting Change	(14,782)	328,108	372,201
Cumulative effect of accounting change, net of tax of $3,613	—	—	5,832
Net (Loss) Income	$(14,782)	$ 328,108	$ 378,033

See Notes to the Consolidated Financial Statements

RELIANT ENERGY RETAIL HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2003
	(Thousands of dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 386,819	$ 9,856
Accounts and notes receivable, principally customer, net	319,284	91,088
Note receivable related to receivables facility	167,996	393,822
Trading and derivative assets	53,220	45,432
Trading and derivative assets — affiliated company, net	97,194	13,067
Margin deposits on energy trading and hedging activities	—	12,250
Accumulated deferred income taxes	—	64,376
Prepayments and other current assets	33,415	50,647
Total current assets	1,057,928	680,538
Property, Plant and Equipment, net	182,778	181,994
Other Assets:		
Goodwill, net	31,631	31,631
Other intangibles, net	4,001	3,144
Investment in unconsolidated subsidiary	8,321	15,838
Trading and derivative assets	7,845	5,507
Trading and derivative assets — affiliated company, net	13,212	315
Notes receivable — affiliated company	—	724,091
Accumulated deferred income taxes	34,909	—
Other	2,938	2,079
Total other assets	102,857	782,605
Total Assets	$1,343,563	$1,645,137
LIABILITIES AND MEMBER'S EQUITY		
Current Liabilities:		
Accounts payable, principally trade	$ 146,691	$ 174,244
Accounts payable — affiliated companies	344,503	17,717
Trading and derivative liabilities	89,546	11,478
Customer deposits	51,750	57,169
Current portion of long-term debt	4,981	3,837
State income taxes payable	30,321	41,058
Accumulated deferred income taxes	9,929	—
Other taxes payable	31,113	32,314
Accrual for payment to Centerpoint Energy, Inc.	—	175,000
Accrued transmission and distribution charges	61,606	52,983
Other	22,706	38,099
Total current liabilities	793,146	603,899
Other Liabilities:		
Trading and derivative liabilities	9,230	251
Accrual for payment to CenterPoint Energy, Inc.	128,300	—
Notes payable — affiliated company	64,229	—
Accumulated deferred income taxes	—	24,778
Other	7,752	5,627
Total other liabilities	209,511	30,656
Long-term Debt	3,837	—
Commitments and Contingencies		
Member's equity (including accumulated other comprehensive income of $9,236, net of tax)	337,069	1,010,582
Total Liabilities and Member's Equity	$1,343,563	$1,645,137

See Notes to the Consolidated Financial Statements

RELIANT ENERGY RETAIL HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2001	2002	2003
	(Thousands of dollars)		
Cash Flows from Operating Activities:			
Net (loss) income	$(14,782)	$ 328,108	$ 378,033
Adjustments to reconcile net (loss) income to net cash (used in) provided by operating activities:			
Cumulative effect of accounting change, net of tax	—	—	(5,832)
Depreciation and amortization	10,843	26,061	35,911
Deferred income taxes	17,204	(43,331)	(49,295)
Net trading and derivative assets and liabilities	(73,128)	5,297	48,291
Accrual for payment to CenterPoint Energy, Inc.	—	128,300	46,700
Federal income tax contribution from Reliant Resources, Inc.	—	75,529	242,678
Changes in other assets and liabilities:			
Accounts and notes receivable and unbilled revenues, net	(34,555)	(545,149)	(28,190)
Notes receivable facility proceeds	—	95,000	23,000
Prepayments and other current assets	157	(31,781)	(17,232)
Other assets	28,799	(1,943)	1,037
Margin deposits on energy trading and hedging activities, net	—	—	(12,250)
Net trading and derivative assets and liabilities	—	—	65,596
Accounts payable	8,023	125,220	27,553
Customer deposits	8	51,743	5,419
Accounts and notes receivable/payable — affiliated companies, net	10,334	(67,788)	67,340
Income taxes payable	2,736	33,354	10,737
Other taxes payable	704	30,216	1,201
Transmission and distribution charges accrued	3,335	61,606	(8,623)
Other current liabilities	6,038	(22,499)	15,392
Other liabilities	4,051	(4,801)	(2,394)
Net cash (used in) provided by operating activities	(30,233)	243,142	845,072
Cash Flows from Investing Activities:			
Capital expenditures	(99,607)	(56,428)	(34,136)
Other	—	607	—
Net cash used in investing activities	(99,607)	(55,821)	(34,136)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	—	13,537	—
Payments of long-term debt	—	(4,719)	(4,981)
Changes in notes with Reliant Resources, Inc.	136,511	180,960	(1,182,918)
Contributions from member	—	1,980	—
Net cash provided by (used in) financing activities	136,511	191,758	(1,187,899)
Net Change in Cash and Cash Equivalents	6,671	379,079	(376,963)
Cash and Cash Equivalents at Beginning of Period	1,069	7,740	386,819
Cash and Cash Equivalents at End of Period	$ 7,740	$ 386,819	$ 9,856
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest paid	$ 79	$ 803	$ 5,615
Interest paid to affiliates, net (net of amounts capitalized)	9,516	—	—
Income taxes paid (net of income tax refunds received)	(28,747)	138,537	21,898
Non-cash Disclosure:			
Contributions from member	1,176	76,160	286,244

See Notes to the Consolidated Financial Statements

RELIANT ENERGY RETAIL HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF MEMBER'S (DEFICIT) EQUITY AND COMPREHENSIVE INCOME/(LOSS)

	Member's (Deficit) Equity	Comprehensive (Loss) Income
	(Thousands of Dollars)	
Balance at December 31, 2000	$ (55,573)	
Net loss	(14,782)	$(14,782)
Contributions from member	1,176	
Comprehensive loss		$(14,782)
Balance at December 31, 2001	(69,179)	
Net income	328,108	$328,108
Contributions from member	78,140	
Comprehensive income		$328,108
Balance at December 31, 2002	337,069	
Net income	378,033	$378,033
Contributions from member	286,244	
Other comprehensive income loss:		
Deferred gain from cash flow hedges, net of tax of $18,546	30,018	30,018
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $12,775	(20,782)	(20,782)
Comprehensive income		$387,269
Balance at December 31, 2003	$1,010,582	

See Notes to the Consolidated Financial Statements

RELIANT ENERGY RETAIL HOLDINGS, LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

(a) Background.

Reliant Energy Retail Holdings, LLC (Retail Holdings), a wholly-owned subsidiary of Reliant Resources, Inc. (Reliant Resources), was formed September 1, 2000 in Delaware. Reliant Resources is the sole member and holds all 1,000 shares of Retail Holdings. Retail Holdings and its subsidiaries are collectively referred to herein as "the Company." Prior to September 30, 2002, the majority of Reliant Resources' common stock was owned by CenterPoint Energy, Inc. (CenterPoint), a regulated energy services and delivery company. CenterPoint served the electricity customers in Houston, Texas until January 1, 2002, when the electricity market opened to retail competition. On September 30, 2002, CenterPoint distributed all of the 240 million shares of Reliant Resources' common stock it owned to its common shareholders (Distribution).

The Company provides electricity products and services to end-use retail customers, ranging from residential and small commercial customers to large commercial, industrial and institutional customers, primarily in Texas. In 2003, the Company began providing retail energy products and services to small and large commercial, industrial and institutional customers in New Jersey and Maryland.

Certain of the Company's wholly-owned subsidiaries include Reliant Energy Retail Services, LLC (Retail Services), formed in September 2000; Reliant Energy Solutions, LLC (Solutions), formed in April 1996; Reliant Energy Electric Solutions, LLC (Electric Solutions), formed in January 2002; StarEn Power, LLC (StarEn Power), formed in November 2000; Reliant Energy Solutions East, LLC (Solutions East), formed in February 2002 and Reliant Energy Renewables, Inc. (Renewables), formed in April 2000. In December 2000, Reliant Resources contributed the operations of Retail Services and the member's equity of Solutions to Retail Holdings. In accordance with accounting principles generally accepted in the United States of America (GAAP), the transfers from Reliant Resources were accounted for as a reorganization of entities under common control. In January 2003, the Company purchased all the outstanding common stock in Renewables from Reliant Energy Power Generation, Inc., an affiliated company and an indirect wholly-owned subsidiary of Reliant Resources for $27,000 and assumed all notes payable to affiliated companies. The purchase price was based on Renewables' book value. The acquisition was treated as a reorganization of entities under common control.

(b) Basis of Presentation.

The consolidated statements of operations include general corporate expenses allocated by Reliant Resources to the Company and by CenterPoint to the Company during 2001. All of the allocations in the consolidated financial statements are based on assumptions that management believes are reasonable under the circumstances. However, these allocations may not necessarily be indicative of the costs and expenses that would have resulted if the Company had been operated as a stand-alone entity. Additionally, costs to manage the Company's supply might be greater if incurred on a stand-alone basis.

(2) Summary of Significant Accounting Policies

(a) Reclassifications.

Some amounts from the previous years have been reclassified to conform to the 2003 presentation of financial statements. These reclassifications do not effect earnings.

(b) Use of Estimates and Market Risk and Uncertainties.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of

contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company's critical accounting estimates include: (a) trading and derivative activities, (b) estimated revenues and energy supply costs and (c) contingencies.

The Company is subject to the risk associated with price movements of energy commodities and the credit risk associated with its commercial activities. For additional information regarding these risks, see notes 2(d) and 6. The Company is subject to risks relating to the reliability of the systems, procedures and other infrastructure necessary to operate the business. The Company is also subject to risks relating to changes in laws and regulations; the outcome of pending lawsuits, governmental proceedings and investigations; the effects of competition; liquidity concerns in its markets; the availability of adequate supplies of electricity; weather conditions; the creditworthiness or financial distress of its counterparties; actions by rating agencies with respect to Reliant Resources or its competitors; political, legal, regulatory and economic conditions and developments; the successful operation of deregulating power markets and other items.

(c) Principles of Consolidation.

The accounts of the Company and its wholly-owned subsidiaries are included in the consolidated financial statements except for a receivables facility arrangement, which involves a qualified special purpose entity (QSPE) formed as a bankruptcy remote subsidiary in 2002, that the Company entered into with financial institutions that purchase undivided interests in the Company's accounts receivable from certain retail customers (see note 12). All significant intercompany transactions and balances are eliminated in consolidation.

(d) Revenues and Accounting for Hedging and Trading Activities.

Electricity Revenues. The Company records gross revenues for energy sales and services to residential, small commercial and large commercial, industrial and institutional electric customers that have not executed a contract under the accrual method and these revenues generally are recognized upon delivery. Electricity sales to large commercial, industrial and institutional customers under contracts executed after October 25, 2002 are typically accounted for under the accrual method and these gross revenues are generally recognized upon delivery.

Electricity sales to large commercial, industrial and institutional customers under contracts executed before October 25, 2002 were accounted for under the mark-to-market method of accounting upon contract execution. See further discussion below of the impact of implementation of Emerging Issues Task Force (EITF) Issue No. 02-03, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," (EITF No. 02-03) rescinding EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," (EITF No. 98-10).

The determination of retail energy sales is based on the reading of customer meters by the transmission and distribution utilities. The transmission and distribution utilities in Texas send the information to the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ERCOT ISO), which in turn sends the information to the Company. The Company may be limited in its ability to confirm the accuracy of such information. This activity occurs 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. Unbilled revenue is estimated each month based on estimated volumes for each customer class and derived from weather factors and analyses of historical trends and experience. As of December 31, 2002 and 2003, the Company had accrued unbilled revenues of $216 million and $290 million, respectively. As additional information becomes available, the Company revises its estimated revenues related to prior periods and records the

results in subsequent periods. The Company believes that the estimates and assumptions utilized to recognize revenues are reasonable and represent its best estimates. However, actual results can differ from those estimates.

Hedging Activities. Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133), which establishes accounting and reporting standards for derivative instruments. The adoption did not have a material impact to the Company's consolidated financial statements.

If certain conditions are met, the Company may designate a derivative instrument as hedging (a) the exposure to variability in expected future cash flows (cash flow hedge), (b) the exposure to changes in the fair value of an asset or liability (fair value hedge) or (c) the foreign currency exposure of a net investment in a foreign operation. This statement requires that a derivative be recognized at fair value in the balance sheets whether or not it is designated as a hedge. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are designated as normal purchases and sales exceptions and are not reflected in the consolidated balance sheet at fair value. For a derivative that is designated as a cash flow hedge, and depending on its effectiveness, changes in fair value are deferred as a component of accumulated other comprehensive income (loss), net of applicable taxes.

The Company designates its derivatives utilized in non-trading activities as cash flow hedges only if there is a high correlation between price movements in the derivative and the item designated as being hedged. This correlation is measured both at the inception of the hedge and on an ongoing basis, with an acceptable level of correlation of at least 80% to 125% for hedge designation. The gains and losses related to derivative instruments designated as cash flow hedges are deferred in accumulated other comprehensive income (loss), net of tax, to the extent the contracts are effective as hedges, and then are recognized in the results of operations in the same period as the settlement of the underlying hedged transactions. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive income (loss) is reclassified and included in the consolidated statements of operations (a) prior to October 1, 2003, under the captions (i) purchased power, in the case of hedging activities related to physical power purchases and (ii) revenues, in the case of hedging activities related to physical power sales transactions and (b) effective October 1, 2003, under the captions (i) purchased power, in the case of hedging activities related to physical power purchases that do physically flow and (ii) revenues, in the case of hedging activities related to physical power sales transactions and physical power purchases that do not physically flow.

For a derivative not designated as a hedge, changes in fair value are recorded as unrealized gains or losses in the results of operations. If and when correlation ceases to exist at an acceptable level, hedge accounting ceases and changes in fair value are recognized currently in the results of operations. If it becomes probable that a forecasted transaction will not occur, the Company immediately recognizes the respective deferred gains or losses in the results of operations. The associated hedging instrument is then marked to market through the results of operations for the remainder of the contract term unless a new hedging relationship is redesignated. Prior to October 1, 2003, revenues and purchased power related to sale and purchase contracts designated as hedges were generally recorded on a gross basis in the delivery period. In July 2003, the EITF issued EITF No. 03-11, which stated that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. On October 1, 2003, the Company began reporting prospectively the settlement of sales and purchases of purchased power related to the non-trading commodity derivative activities that were not physically delivered on a net basis in the consolidated statement of operations based on the item hedged. This change

resulted in decreased revenues and a corresponding decrease in power of $3 million for the fourth quarter of 2003. The Company believes the application of EITF 03-11 will continue to result in certain amounts of our non-trading commodity derivative activities being reported on a net basis prospectively that were previously reported on a gross basis. EITF No. 03-11 has no impact on margins or net income. Comparative financial statements for prior periods have not been reclassified to conform to this presentation, as it is not required. In addition, it is not practicable to determine sales and purchased power in 2001, 2002 and the nine months ended September 30, 2003 that would have been shown net if EITF No. 03-11 had been applied to the results of operations historically.

In April 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 149 clarifies when a contract with an initial net investment meets the characteristics of a derivative and when a derivative contains a financing component. SFAS No. 149 also amends certain existing pronouncements, which will result in more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003 and should be applied prospectively. The implementation of SFAS No. 149 did not have a material impact on the consolidated financial statements.

For additional discussion of derivative and hedging activities, see note 6.

Trading Activities. In 2002, the EITF reached a consensus that all mark-to-market gains and losses on energy trading contracts should be shown net in the statement of operations whether or not settled physically. Beginning in the quarter ended September 30, 2002, the Company reports all energy trading activities on a net basis in the consolidated statements of operations. Comparative financial statements for prior periods were reclassified to conform to this presentation.

Furthermore, in 2002, the EITF reached a consensus to rescind EITF No. 98-10. All contracts that would have been accounted for under EITF No. 98-10, and that do not fall within the scope of SFAS No. 133, may no longer be marked to market through earnings, effective October 25, 2002. This transition was effective (a) on January 1, 2003 for contracts executed prior to October 25, 2002 and (b) on October 25, 2002 for contracts executed on or after that date. The Company recorded a cumulative effect of a change in accounting principle of $6 million gain, net of tax of $4 million, effective January 1, 2003, related to EITF No. 02-03. The cumulative effect reflects the fair value, as of January 1, 2003, of contracts executed prior to October 25, 2002 that had been marked to market under EITF No. 98-10 that did not meet the definition of a derivative under SFAS No. 133.

Prior to 2003, electricity sales to large commercial, industrial and institutional customers under executed contracts (and the related energy supply contracts) for contracts executed prior to October 25, 2002 were accounted for under the mark-to-market method of accounting pursuant to EITF No. 98-10. Accordingly, these contractual commitments were recorded at fair value in revenues on a net basis upon contract execution. As of December 31, 2002, the recognized, unrealized balances were recorded at fair value in trading and derivative assets/liabilities in the consolidated balance sheet. Beginning in January 2003, the Company began applying the normal purchase and sale exception of SFAS No. 133 to a substantial portion of the large commercial, industrial and institutional sales contracts and the related energy supply agreements and began utilizing accrual accounting. The related revenues and energy supply costs are recorded on a gross basis in the results of operations. The results of operations related to the electricity sales to large commercial, industrial and institutional customers for contracts executed prior to October 25, 2002 are not comparable between 2001, 2002 and 2003 because of this change. During 2001 and 2002, the Company recognized $73 million and $(6) million, respectively, of unrealized net gains (losses) related to our electricity sales to large commercial, industrial and institutional customers and the related energy supply contracts. During 2003, volumes were delivered under electricity sales to large commercial, industrial and institutional customers under executed contracts and the related energy supply

contracts for which $66 million was previously recognized as unrealized earnings. As of December 31, 2003, the Company has unrealized gains that have been previously recorded in the results of operations of $27 million that will be realized upon delivery of the electricity ($21 million in 2004 and $6 million in 2005). These unrealized gains are recorded in trading and derivative assets/liabilities in the consolidated balance sheets of an affiliated company, as of December 31, 2003 and the related contracts are accounted for as cash flow hedges or normal purchases and sales contracts under SFAS No. 133. See note 3(b).

During 2001 and 2002, the Company recorded $74 million and $43 million, respectively, of fair value at the contract inception related to trading activities, including electricity sales to large commercial, industrial and institutional customers and the related energy supply contracts. Inception gains recorded were evidenced by quoted market prices and other current market transactions for energy trading contracts with similar terms and counterparties.

For additional discussion regarding trading revenue recognition and the related estimates and assumptions that can affect reported amounts of such revenues, see note 6.

Set-off of Trading and Derivative Assets and Liabilities. Where trading and derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts," are met, the Company presents trading and derivative assets and liabilities on a net basis in the consolidated balance sheets. Trading and derivative assets/liabilities and accounts receivable/payable are presented separately in the consolidated balance sheets.

(e) General and Administrative Expenses.

The general and administrative expenses in the consolidated statements of operations include (a) employee-related costs, (b) certain contractor costs, (c) advertising, (d) bad debt expense, (e) marketing and market research, (f) corporate and administrative services (including management services, financial and accounting, cash management and treasury support, legal, information technology system support, office management and human resources) and (g) certain benefit costs. Some of these expenses are allocated from affiliates, see further discussion in note 3.

(f) Property, Plant and Equipment and Depreciation Expense.

The Company records property, plant and equipment at historical cost. Depreciation is computed using the straight-line method based on estimated useful lives. Property, plant and equipment includes the following:

	Estimated Useful Lives (Years)	December 31, 2002	December 31, 2003
		(In millions)	
Information technology	3 - 10	$170	$193
Generation facilities	20	23	30
Machinery, telecommunications equipment and other	5	14	14
Furniture and leasehold improvements	3 - 7	9	13
Total		216	250
Accumulated depreciation		(33)	(68)
Property, plant and equipment, net		$183	$182

Information technology assets include hardware, software, consultant time, in-house labor and capitalized interest used to design and implement various systems, including the customer billing and

energy supply systems. Costs are capitalized in accordance with Statement of Position 98-1, "Accounting for Cost of Computer Software Developed or Obtained for Internal Use".

Depreciation expense was $8 million, $25 million, and $35 million for 2001, 2002 and 2003, respectively.

The Company periodically evaluates property, plant and equipment for impairment when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. A resulting impairment loss is highly dependent on the underlying assumptions.

(g) Goodwill and Amortization Expense.

The Company records goodwill for the excess of the purchase price over the fair value assigned to the net assets of an acquisition. Through 2001, the Company amortized goodwill on a straight-line basis over 15 years. Pursuant to the Company's adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) on January 1, 2002, the Company discontinued amortizing goodwill. See note 5 for a discussion regarding the Company's adoption of SFAS No. 142. Goodwill amortization expense was $2 million for 2001. Amortization expense for other intangibles was $1 million for 2001, 2002 and 2003. See also note 5.

The Company periodically evaluates goodwill and other intangibles when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. In 2001, the determination of whether an impairment had occurred was based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. Effective January 1, 2002, goodwill and other intangibles are evaluated for impairment in accordance with SFAS No. 142 (see note 5). For further discussion of goodwill and other intangible asset impairment analyses in 2002 and 2003, see note 5.

(h) Stock-Based Compensation Plans.

The Company applies the intrinsic value method of accounting for employee stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25). Under the intrinsic value method, no compensation expense is recorded when options are issued with an exercise price equal to or greater than the market price of the underlying stock on the date of grant. Since the stock options to employees have all been granted with the exercise price equal to market value at date of grant, no compensation expense has been recognized under APB No. 25. The Company complies with the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) and SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment to SFAS No. 123" (SFAS No. 148) and discloses the pro forma effect on net income (loss) as if the fair value method of accounting had been applied to all stock awards. The FASB has announced that it plans to require all companies to expense the fair value of employee stock options in 2005. The FASB is still evaluating "fair value" valuation models and other items.

If compensation costs had been determined as prescribed by SFAS No. 123, net income (loss) would have approximated the following pro forma results for 2001, 2002 and 2003, which take into account the

amortization of stock-based compensation, including performance shares, purchases under the employee stock purchase plan and stock options, to expense on a straight-line basis over the vesting periods:

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Net (loss) income, as reported	$(15)	$328	$378
Add: Stock-based employee compensation expense included in reported net income/loss, net of related tax effects	1	1	1
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(5)	(7)	(7)
Pro forma net (loss) income	$(19)	$322	$372

For further information regarding Reliant Resources' and CenterPoint's stock-based compensation plans in which the Company's employees participate, see note 8.

(i) Capitalization of Interest Expense.

Interest expense is capitalized as a component of major projects under construction and is amortized over the estimated useful lives of the assets. It is principally applied to information technology projects. During 2001, 2002 and 2003 the Company capitalized interest of $4 million, $2 million and $1 million, respectively.

(j) Income Taxes.

Although the Company is organized as a limited liability company, and therefore has no federal income tax liability, the Company calculates an income tax provision on a separate return basis. The Company uses the asset and liability method of accounting for deferred income taxes and measures deferred income taxes for all significant income tax temporary differences. The current deferred tax assets and liabilities are shown net in the consolidated balance sheets because the asset/liability is with Reliant Resources. The non-current deferred tax assets and liabilities are shown net in the consolidated balance sheets for the same reason. For additional information regarding income taxes, see note 9.

Prior to October 1, 2002, the Company was included in the consolidated federal income tax returns of CenterPoint. As of October 1, 2002, the Company is included in the consolidated tax returns of Reliant Resources and calculates its income tax provision on a separate return basis. Pursuant to the Company's tax sharing agreement with Reliant Resources, Reliant Resources pays all federal income taxes on its behalf and is entitled to any related tax refunds. The difference between the Company's current federal income tax expense or benefit, as calculated on a separate return basis, and related amounts paid or received to/from Reliant Resources, if any, are recorded on its books as adjustments to member's equity on its consolidated balance sheets. During 2002 and 2003, Reliant Resources made equity contributions to the Company for deemed distributions related to current federal income taxes of $76 million and $243 million, respectively.

(k) Cash and Cash Equivalents.

The Company records as cash and cash equivalents all highly liquid short-term investments with original maturities or remaining maturities at date of purchase of three months or less.

(l) Allowance for Doubtful Accounts.

Accounts and notes receivable, principally customers, net in the consolidated balance sheets are net of an allowance for doubtful accounts of $36 million and $38 million at December 31, 2002 and 2003, respectively. The net provision for doubtful accounts in the consolidated statements of operations for 2001, 2002 and 2003 was $3 million, $73 million and $65 million, respectively. The Company accrues a provision for doubtful accounts based upon estimated percentages of uncollectible revenues. The Company determines these percentages from counterparty credit ratings, historical collections, accounts receivable aging analyses and other factors. The Company reviews the provision and estimated percentages periodically and adjusts them as appropriate. The Company writes-off accounts receivable balances against the allowance for doubtful accounts when it deems the receivable to be uncollectible.

(m) New Accounting Pronouncements.

As of February 20, 2004, no standard setting body or authoritative body has established new accounting pronouncements or changes to existing accounting pronouncements that would have a material impact to the Company's results of operations, financial position or cash flows, for which the Company has not already adopted and/or disclosed elsewhere in these notes.

(3) Related Party Transactions

Accounts and notes payable — affiliated companies relate primarily to purchased power, interest, charges for services and office space rental. The affiliate accounts payable and notes payable are generally settled on a monthly basis, with the exception of a $375 million affiliate note as of December 31, 2002 from Reliant Resources. These items are discussed more fully below.

(a) Reliant Resources.

Corporate Support Services. Reliant Resources provides the Company various corporate support services, including accounting, finance, investor relations, tax, risk, treasury, planning, legal, communications, governmental and regulatory affairs, human resources, information technology services and other shared services such as corporate security, facilities management, accounts payable, purchasing, payroll and office support services. The costs of services have been directly charged or allocated to the Company using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses and employees. These charges and allocations are not necessarily indicative of what would have been incurred had the Company been a stand-alone entity. Amounts charged and allocated to the Company for these services were $13 million, $65 million and $93 million for 2001, 2002 and 2003, respectively. Included in these amounts are $4 million, $8 million and $10 million, for 2001, 2002 and 2003, respectively, for the Company's share of allocated rent expense, which is included in general and administrative expense in the consolidated statements of operations.

Reliant Resources manages the Company's daily cash balances. Excess cash is advanced to Reliant Resources, which provides a cash management function, and is recorded in long-term note receivable — affiliated company in the consolidated balance sheets. As cash is required to fund operations, the Company's bank accounts are funded by Reliant Resources, and those changes are recorded as a reduction in long-term note receivable — affiliate. The Company records interest income or expense, based on whether the Company invested excess funds, or borrowed funds from Reliant Resources. The amount of interest (expense) income is $(13) million, $(1) million and $20 million, respectively.

On December 31, 2002, the Company borrowed $375 million from Reliant Resources, which is included in accounts and notes payable — affiliated companies on the consolidated balance sheets as of

December 31, 2002. This note was repaid on April 11, 2003 and bore interest at the weighted average corporate borrowing interest rate.

Naming Rights to the Houston Sports Complex. In October 2000, Reliant Resources acquired the naming rights for a football stadium and other convention and entertainment facilities included in the stadium complex. The agreement extends through 2032. In addition to naming rights, the agreement provides Reliant Resources with significant sponsorship rights. The aggregate cost of the naming rights is approximately $300 million. Starting in 2002, Reliant Resources began to pay $10 million each year, which will continue through 2032, for the annual naming, advertising and other benefits under this agreement. These costs are charged to the Company by Reliant Resources and are included in general and administrative expense in the consolidated statements of operations.

Payment to CenterPoint in 2004. Consistent with the Texas electric restructuring law, Reliant Resources expects to make a payment to CenterPoint for the Company's residential customers. This provision of the law requires a payment be made to CenterPoint unless, as of December 31, 2003, 40% or more of the electric power consumed in 2000 by each class of customer in the Houston service territory was provided by other retail electric providers. In 2002, the Company entered into an agreement with Reliant Resources in which the Company agreed to reimburse Reliant Resources for the payment. This agreement was made because Retail Services receives the benefit of these customers and related profit margin. Currently, the Company estimates the payment to be $175 million and expects that the payment will be made in the fourth quarter of 2004. This amount is computed by multiplying $150 by the number of residential customers that the Company served on January 1, 2004 in the Houston service territory, less the number of residential customers the Company served in other areas of Texas on that same date. The Company recognized $128 million (pre-tax) in the third and fourth quarters of 2002 and $47 million (pre-tax) in the first quarter of 2003 for a total accrual of $175 million as of December 31, 2003. The Company recognized the total obligation over the period the Company recognized the related revenues.

The Company will not be required to make a similar payment for small commercial customers because in January 2004 the Public Utility Commission of Texas (PUCT) found that the 40% target for small commercial customers was reached before the end of 2003.

(b) Reliant Energy Services, Inc.

Reliant Energy Services, Inc. (Reliant Energy Services) provides commodity price risk management and supply procurement services for the Company. The administrative costs for these services were $8 million and $2 million for 2002 and 2003, respectively. These costs did not exist in 2001.

Reliant Energy Services enters into contracts with third parties for the purposes of supplying the Company with some of the electricity necessary to serve its retail customers. These supply contracts are subject to the provisions of the master commodity purchase and sale agreements, master netting arrangements, and other contractual arrangements that Reliant Energy Services utilizes with third-party customers and suppliers in connection with Reliant Energy Services' supply portfolio management activities, including those activities undertaken for the Company. Consequently, the cost associated with credit support for the supply portfolio managed by Reliant Energy Services for the Company could differ significantly from those that the Company would experience if it managed the electricity supply portfolio directly with third parties.

The Company reimburses Reliant Energy Services for the ultimate price of any electricity sold from Reliant Energy Services to the Company, including costs of derivative instruments, upon final delivery of that electricity. The Company does not account for the unrealized value associated with the derivative instruments executed by Reliant Energy Services with third parties because the contracts are executed by Reliant Energy Services.

The net purchases are included in purchased power expense in the consolidated statements of operations, except for purchases related to supply for large commercial, industrial and institutional customers under contracts entered into prior to October 25, 2002 which are included in trading margins. Purchased power from Reliant Energy Services was $3 million, $2.0 billion and $522 million for 2001, 2002 and 2003, respectively. Sales and purchases of electricity related to large commercial, industrial and institutional customers under contracts entered into prior to October 25, 2002, are accounted for on the mark-to-market basis (see note 2(d) for further discussion) and are presented on a net basis in the consolidated statements of operations. Unrealized gains related to supply contracts accounted for on a mark-to-market basis totaled $142 million during 2002. During 2003, the Company recognized $93 million of previously unrealized losses related to supply contracts accounted for on a mark-to-market basis prior to 2003. These costs did not exist in 2001. Purchases of electricity from Reliant Energy Services included in trading margins for 2001, 2002, and 2003 were $14 million, $541 million and $0, respectively.

During 2003, certain supply contracts were transferred from Reliant Energy Services to the Company. The value of those contracts was $43 million, net of tax of $27 million. This transfer was included in contributions from member in the consolidated statement of member's (deficit) equity.

(c) Reliant Energy Power Generation, Inc.

Reliant Energy Power Generation, Inc. provides project management services related to the construction of the Renewables facilities. The costs for these services were $1 million in 2002 and 2003. These services were not incurred in 2001.

(d) CenterPoint.

Prior to the Distribution, CenterPoint was a related party. Transactions with CenterPoint subsequent to the Distribution are not reported as affiliated transactions. The Company had, or continues to have (as indicated) the following agreements/transactions with CenterPoint:

Corporate Support Services. During 2001, CenterPoint provided the Company with various corporate support services, information technology services and other previously shared services such as corporate security, facilities management, payroll, accounts payable, office support services, and purchasing services. CenterPoint currently provides services involving remittance processing, bill inserting and bill printing. Certain of these arrangements will continue until December 31, 2004; however, the Company has the right to terminate categories of services at an earlier date. The charges paid to CenterPoint for these services allow CenterPoint to recover its fully allocated costs, plus out-of-pocket costs and expenses. The costs of services have been directly charged or allocated using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment, and proportionate corporate formulas based on assets, operating expenses and employees. These charges and allocations are not necessarily indicative of what would have been incurred had the Company been an unaffiliated entity. Amounts charged to the Company for these services were $2 million and $3 million during 2001 and the nine months ended September 30, 2002, the date of the Distribution, and are included in operation and maintenance expense in the consolidated statements of operations. It is not anticipated that a change, if any, in these costs and revenues would have a material effect on the Company's consolidated results of operations, cash flows or financial position.

Services Provided to CenterPoint. During 2001, the Company provided billing, customer service, credit and collection and remittance services to certain of CenterPoint's regulated utilities. The charges CenterPoint paid for these services allowed the Company to recover its fully allocated costs of providing the services, plus out-of-pocket costs and expenses. The Company recorded $53 million of revenues and costs related to the provision of these services during 2001.

During 2001, Renewables sold $1 million of electricity to CenterPoint.

Cash for customer deposits and the related liability of $46 million were transferred from CenterPoint to the Company, effective with the transfer of the customers on January 1, 2002.

The Company also pays to CenterPoint a regulated tariff rate for electric transmission service for delivering electricity to customers in the Houston area. For the nine months ended September 30, 2002, the date of the Distribution, this expense was $664 million and is included in purchased power expense in the consolidated statement of operations.

(4) Agreements Related to Texas Genco

Texas Genco, LP is a wholly-owned subsidiary of Texas Genco Holdings, Inc., a majority-owned subsidiary of CenterPoint, and owns the Texas generating assets formerly held by CenterPoint's electric utility division. Texas Genco, LP and Texas Genco Holdings, Inc. are collectively referred to herein as "Texas Genco."

In January 2003, CenterPoint distributed approximately 19% of the common stock of Texas Genco to CenterPoint shareholders. CenterPoint granted Reliant Resources an option to purchase all of the remaining shares of common stock of Texas Genco held by CenterPoint. The option expired unexercised on January 24, 2004.

Texas Genco, as the affiliated power generator of CenterPoint's electric utility, is required by law to sell at auction 15% of the output of its installed generating capacity. These auction obligations will continue until January 2007, unless at least 40% of the electricity consumed by residential and small commercial customers in CenterPoint's service territory is being provided by other retail electric providers. The Company is not currently able to participate in these legally mandated capacity auctions. Under CenterPoint's prior agreement with Reliant Resources, Texas Genco was required to auction the remainder of its capacity after certain other adjustments and it had the right to participate directly in such auctions. Texas Genco's obligation to auction its remaining capacity and the Company's associated rights terminated when Reliant Resources decided not to exercise its option to acquire CenterPoint's ownership interest in Texas Genco.

The Company has a master power purchase contract with Texas Genco covering, among other things, purchases of capacity and/or energy from Texas Genco's generating units. In connection with this contract, the Company has granted Texas Genco a security interest in its rights in the accounts receivables and related assets of certain of its subsidiaries. The liens on the Company's rights in the accounts receivable and related assets are junior to the Company's receivables facility and senior to Reliant Resources' March 2003 credit facilities and to Reliant Resources' senior secured notes. See note 12. The term of the master power purchase contract terminates on January 24, 2005.

The Company has purchased entitlements to some of the generation capacity of electric generation assets of Texas Genco. Reliant Resources, through the Company, purchased these entitlements in capacity auctions conducted by Texas Genco. As of December 31, 2003, the Company had purchased entitlements to capacity of Texas Genco averaging 6,376 megawatts (MW) per month in 2004 and 923 MW per month in 2005. The Company's anticipated capacity payments related to these capacity entitlements are $714 million. The capacity entitlements are accounted for as normal purchases under SFAS No. 133. See notes 2(d) and 6 for discussion of the Company's derivative financial instruments.

Under a support agreement with CenterPoint, the Company provides systems, technical, programming and consulting support services and hardware maintenance (but excluding plant-specific hardware) necessary to provide dispatch planning, settlement and communication with the independent system operator. The fees charged for these services are designed to allow the Company to recover its fully

allocated direct and indirect costs and reimbursement of out-of-pocket expenses. The term of this agreement will end on the first occur of (a) CenterPoint's sale of Texas Genco, or all or substantially all of the generating assets of Texas Genco or (b) May 31, 2005; however, Texas Genco may extend the term of this agreement until December 31, 2005. In addition, Texas Genco has the right to terminate the agreement upon 90 days' notice. The fees charged for services provided are $2 million in 2003. There were no services performed by the Company for these services in 2001 and 2002.

(5) Goodwill and Intangibles

In July 2001, the FASB issued SFAS No. 142, which states that goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and charged to results of operations in periods in which the recorded value of goodwill and certain intangibles with indefinite lives exceeds their fair values. The Company adopted the provisions of the statement effective January 1, 2002, and discontinued amortizing goodwill into the results of operations. A reconciliation of 2001 reported net income adjusted for the exclusion of goodwill amortization with a comparison to 2002 and 2003 follows:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Reported net (loss) income	$(15)	$328	$378
Add: Goodwill amortization, net of tax	2	—	—
Adjusted net (loss) income	$(13)	$328	$378

The Company recorded goodwill for the excess of the purchase price over the fair value assigned to the net assets of the acquisition of the energy services division of Southland Industries in 1999. This division contained contracts for performing energy-related services for commercial customers.

Intangibles. The Company recognizes specifically identifiable intangibles, which include (a) demand side management contracts (DSM), which are contracts that allow the Company to install energy efficiency equipment for clients and share in future energy savings, (b) permanent seat licenses (PSL) at Reliant Stadium, (c) air emissions regulatory allowances and (d) a non-compete agreement. The DSM contracts and the non-compete agreement were purchased as part of an acquisition of the energy services division of Southland Industries in 1999.

The air emissions regulatory allowances were purchased in 2000 by Renewables. Other intangible assets consist of the following:

		December 31,			
		2002		2003	
	Weighted-Average Amortization Period (Years)	Carrying Amount	Accumulated Amortization	Carrying Amount	Accumulated Amortization
		(In millions)			
DSM	5	$ 2	$(1)	$ 2	$(1)
PSL	5	2	—	2	(1)
Air emissions regulatory allowances	—	1	—	1	—
Non-compete agreement	5	—	—	—	—
Total		$ 5	$(1)	$ 5	$(2)

The Company amortizes acquired intangibles, other than air emissions regulatory allowances, on a straight-line basis over their contractual or estimated useful lives. The Company does not amortize its air emissions regulatory allowances because they have been issued in perpetuity by the Texas Commission of Environmental Quality.

Estimated amortization expense for the next five years is as follows (in millions):

2004	$ 1
2005	1
2006	1
2007	—
2008	—
Total	$ 3

Goodwill. There were no changes in the carrying amount of goodwill in 2002 and 2003.

SFAS No. 142 requires goodwill to be tested at least annually and more frequently in certain circumstances. The date of the annual impairment test was November 1 for 2002 and 2003. A goodwill impairment test is performed in two steps. The initial step is designed to identify potential goodwill impairment by comparing an estimate of the fair value to its carrying value, including goodwill. If the carrying value exceeds the fair value, a second step is performed, which compares the implied fair value of the goodwill with the carrying amount of that goodwill, to measure the amount of the goodwill impairment, if any. Based on the first step of the goodwill impairment test effective November 1, 2002, the Company's goodwill was not impaired. In 2003, the Company met certain criteria which allowed it to carry forward the 2002 fair value. Goodwill was not impaired for 2003, as the fair value exceeded the carrying value.

(6) Derivative Instruments, Including Energy Trading Activities

The Company is exposed to various market risks. These risks arise from the ownership of the Company's assets and operation of the business. The Company routinely utilizes derivative instruments such as futures, physical forward contracts, swaps and options to mitigate the impact of changes in electricity prices on the operating results and cash flows.

Reliant Resources has a risk control framework, which the Company is subject to, designed to monitor, measure and define appropriate transactions to hedge and manage the risk in the existing portfolio of assets and contracts and to authorize new transactions. These risks fall into three different categories: market risk, credit risk and operational risk. The Company believes that it has effective procedures for evaluating and managing these risks to which it is exposed. Key risk control activities include definition of appropriate transactions for hedging, 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, value-at-risk and other risk measurement metrics. The Company seeks to monitor and control its risk exposures through a variety of separate but complementary processes and committees, which involve business unit management, senior management and Reliant Resources' board of directors.

The primary types of derivatives used are physical forward contracts, which are commitments to purchase or sell energy commodities in the future.

Trading and derivative assets and liabilities at December 31, 2002 and 2003 include amounts for non-trading and trading activities, as follows:

	Assets		Liabilities		Net Assets (Liabilities)
	Current	Long-term	Current	Long-term	
			(In millions)		
December 31, 2002:					
Trading activities	$ 53	$ 8	$(89)	$(9)	$(37)
Trading activities — affiliated company, net	97	13	—	—	110
Total	$150	$21	$(89)	$(9)	$ 73
December 31, 2003:					
Non-trading activities:					
Commodity cash flow hedges — offset to accumulated other comprehensive income (loss)	$ 23	$—	$ (6)	$—	$ 17
Derivatives marked to market through earnings	54	6	(37)	—	23
Subtotal	77	6	(43)	—	40
Non-trading derivatives — affiliated company, net	13	—	—	—	13
Total	90	6	(43)	—	53
Set-off adjustments	(32)	—	32	—	—
Total trading and derivative assets and liabilities	$ 58	$ 6	$(11)	$—	$ 53

(a) Non-Trading Derivative Activities.

To reduce the risk from market fluctuations in the results of operations and the resulting cash flows, the Company may enter into energy derivatives in order to hedge expected purchases and sales of electric power (non-trading energy derivatives). There were no such activities in 2001 and 2002.

The fair values of the non-trading derivative activities as of December 31, 2003 are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

Below is the pre-tax income of the non-trading derivative instruments, including non-trading energy derivatives, both from cash flow hedge ineffectiveness and from non-trading derivative mark-to-market income and losses, for 2003 (in millions):

Hedge ineffectiveness(1)	$—
Non-trading derivatives mark-to-market income	23
Total	$23

(1) For 2003, no component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness.

As of December 31, 2003, the Company expects $9 million of accumulated other comprehensive income to be reclassified into the results of operations during 2004. As of December 31, 2003, the

maximum length of time the Company is hedging its exposure to the variability in future cash flows for forecasted transactions is 2 years.

(b) Energy Trading Activities.

Electricity sales to large commercial, industrial and institutional customers under contracts executed before October 25, 2002 were accounted for under the mark-to-market method of accounting upon contract execution (see note 2(d)). The fair values of trading activities as of December 31, 2002, are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

(c) Credit Risks.

Credit risk is inherent in the Company's commercial activities and relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. Reliant Resources has broad credit policies and parameters, which the Company is subject to. The Company seeks to enter into contracts that permit the Company to net receivables and payables with a given counterparty. The Company also enters into contracts that enable the Company to obtain collateral from a counterparty as well as to terminate upon the occurrence of certain events of default. The credit risk control organization establishes counterparty credit limits. Reliant Resources employs tiered levels of approval authority for counterparty credit limits, with authority increasing from the credit risk control organization through senior management. Credit risk exposure is monitored daily and the financial condition of counterparties is reviewed periodically.

If any of the counterparties failed to perform, the Company might be forced to acquire alternative hedging arrangements or be required to replace the underlying commitment at then-current market prices. In this event, the Company might incur additional losses in addition to amounts owed to the Company by the counterparty.

As of December 31, 2003, there was one investment grade counterparty representing 15% of the Company's total credit exposure, net of collateral. The dollar amount of the Company's credit exposure to this counterparty was $21 million as of December 31, 2003. As of December 31, 2003, there were no other counterparties representing greater than 10% of our total credit exposure, net of collateral.

(7) Long-term Debt

On January 1, 2002, the Company sold equipment subject to an operating lease. This transaction was recorded as a borrowing under SFAS No. 13, "Accounting for Leases," because the Company retained substantial risk of ownership in the leased property. The Company is required to either repurchase the lease or remarket the leased equipment in the event that the lessee defaults on the lease. The initial balance of the debt was $14 million and expires on April 2004. As of December 31, 2002 and 2003, the remaining lease obligation was $9 million and $4 million, respectively.

(8) Stock-Based Incentive Compensation Plans and Retirement and Other Benefit Plans

(a) Stock-Based Incentive Compensation Plans.

At December 31, 2003, eligible employees of the Company participate in four incentive plans described below.

The Reliant Resources, Inc. 2002 Long-Term Incentive Plan (2002 LTIP) permits Reliant Resources to grant awards (stock options, restricted stock, stock appreciation rights, performance awards and cash awards) to key employees, non-employee directors and other individuals which the Company expects to

become key employees within the following six months. Subject to adjustment as provided in the plan, the aggregate number of shares of Reliant Resources' common stock that may be issued may not exceed 17,500,000 million shares. Reliant Resources also sponsors the Long-Term Incentive Plan of Reliant Resources, Inc. (2001 LTIP), which was effective January 31, 2001, and was amended to provide that no additional awards would be made under the 2001 LTIP after June 6, 2002. Upon the adoption of the 2002 LTIP, the shares remaining available for grant under the 2001 LTIP, totaling approximately 3.5 million, became available as authorized shares available for grant under the 2002 LTIP. These shares are included in the total of 17,500,000 shares available under the 2002 LTIP. Additionally, any shares forfeited under the 2001 LTIP become available for grant under the 2002 LTIP.

The Reliant Resources, Inc. 2002 Stock Plan (2002 Stock Plan) permits Reliant Resources to grant awards (stock options, restricted stock, stock appreciation rights, performance awards and cash awards) to all employees (excluding officers subject to Section 16 of the Securities Exchange Act of 1934). The board of directors authorized 6,000,000 shares for grant upon adoption of the 2002 Stock Plan. To the extent these 6,000,000 shares were not granted in 2002, the excess shares were canceled. An additional 6,000,000 shares were authorized for the 2003 plan year. The total number of shares is adjusted for new grants, exercises, forfeitures, cancellations and terminations of outstanding awards under the plan throughout the year. Reliant Resources does not plan to authorize additional shares for this plan after the end of the 2003 plan year.

Prior to the IPO, eligible employees participated in a CenterPoint Long-Term Incentive Compensation Plan and other incentive compensation plans (collectively, the CenterPoint Plans) that provided for the issuance of stock-based incentives including performance-based shares, restricted shares, stock options and stock appreciation rights, to key employees including officers. The Reliant Resources, Inc. Transition Stock Plan was adopted to govern the outstanding restricted shares and options of CenterPoint common stock held by employees prior to the Distribution date, under the CenterPoint Plans. There were 9,100,000 shares authorized under the Reliant Resources, Inc. Transition Stock Plan and it is anticipated that no additional shares will be issued.

In addition, in conjunction with the Distribution, Reliant Resources entered into an employee matters agreement with CenterPoint. This agreement covered the treatment of outstanding CenterPoint equity awards (including performance-based shares, restricted shares and stock options) under the CenterPoint Plans held by Reliant Resources employees and CenterPoint employees. According to the agreement, each CenterPoint equity award granted to Reliant Resources employees and CenterPoint employees prior to the agreed upon date of May 4, 2001, that was outstanding under the CenterPoint Plans as of the Distribution date, was adjusted. This adjustment resulted in each individual, who was a holder of a CenterPoint equity award, receiving an adjusted equity award of Reliant Resources common stock and CenterPoint common stock, immediately after the Distribution. The combined intrinsic value of the adjusted CenterPoint equity awards and Reliant Resources equity awards, immediately after the record date of the Distribution, was equal to the intrinsic value of the CenterPoint equity awards immediately before the record date of the Distribution.

Performance-based Shares and Restricted Shares. Performance-based shares and restricted shares have been granted to employees without cost to the participants. The performance-based shares generally vest three years after the grant date based upon performance objectives over a three-year cycle, except as discussed below. The restricted shares vest to the participants at various times ranging from immediate vesting to vesting at the end of a five-year period. During 2001, 2002 and 2003, the Company recorded compensation expense of $2 million, $1 million and $1 million, respectively, related to performance-based and restricted share grants.

Prior to the Distribution, Reliant Resources employees and CenterPoint employees held outstanding performance-based shares and restricted shares of CenterPoint's common stock under the CenterPoint

Plans. On the Distribution date, each performance-based share of CenterPoint common stock outstanding under the CenterPoint Plans, for the performance cycle ending December 31, 2002, was converted to restricted shares of CenterPoint's common stock based on a conversion ratio provided under the employee matters agreement. Immediately following this conversion, outstanding restricted shares of CenterPoint common stock were converted to restricted shares of Reliant Resources' common stock, which shares were subject to their original vesting schedule under the CenterPoint Plans. The conversion ratio was determined using the intrinsic value approach described above. As such, the Company's employees held 160,461 restricted shares outstanding under CenterPoint Plans which were converted to 126,555 restricted shares, of Reliant Resources' common stock, of which a majority vested on December 31, 2002.

The following table summarizes performance-based shares and restricted shares grant activity to employees of the Company for 2001, 2002 and 2003:

	Performance-based Shares	Restricted Shares
Granted during 2001	43,650	—
Outstanding at December 31, 2001	43,650	—
Granted during 2002	41,400	32,500
Outstanding at December 31, 2002	46,650	44,329
Granted during 2003	—	295,713
Outstanding at December 31, 2003(1)	58,500	332,968
Weighted average grant date fair value of shares granted for 2001	$ 30.00	$ —
Weighted average grant date fair value of shares granted for 2002	$ 10.90	$ 8.85
Weighted average grant date fair value of shares granted for 2003	$ —	$ 3.51

(1) The change in performance-based shares between 2002 and 2003 is primarily due to employee transfers.

Stock Options. Under both CenterPoint's and Reliant Resources' plans, stock options generally vest over a three-year period and expire after ten years from the date of grant. The exercise price is equal to or greater than the market value of the applicable common stock on the grant date.

As of the record date of the Distribution, CenterPoint converted all outstanding CenterPoint stock options granted prior to May 4, 2001 (totaling 664,204 stock options held by employees of the Company) to a combination of CenterPoint stock options totaling 664,204 stock options at a weighted average exercise price of $19.02 and Reliant Resources stock options totaling 523,794 stock options with a weighted average exercise price of $9.15. The conversion ratio was determined using an intrinsic value approach as described above.

The following table summarizes stock options outstanding for 2001, 2002 and 2003:

	Options	Weighted Average Exercise Price
Outstanding at December 31, 2001	1,444,912	$29.49
Outstanding at December 31, 2002	2,677,443	$18.78
Outstanding at December 31, 2003	3,227,228	$15.96
Options exercisable at December 31, 2001	—	$ —
Options exercisable at December 31, 2002	851,287	$19.72
Options exercisable at December 31, 2003	1,687,221	$18.99

As of December 31, 2003, exercise prices for Reliant Resources' stock options outstanding and held by the Company's employees ranged from $3.51 to $34.03.

Employee Stock Purchase Plan. In the second quarter 2001, Reliant Resources established the Employee Stock Purchase Plan (ESPP). Under the ESPP, employees may contribute up to 15% of their compensation, as defined, towards the purchase of shares of Reliant Resources common stock at a price of 85% of the lower of the market value at the beginning or end of each six-month offering period. The initial purchase period began on the date of Reliant Resources' initial public offering (May 2001) and ended December 31, 2001. The market value of the shares acquired in any year may not exceed $25,000 per individual. Amounts contributed in excess of $21,250 during a purchase period will be refunded to the employee. The following table details the number of shares (and price per share) issued to employees of the Company under the ESPP for 2002 and 2003 and through January 2004:

	Shares	Price/ Share
January 2002	116,041	$14.07
July 2002	206,565	$ 7.44
January 2003	215,197	$ 2.66
July 2003	685,859	$ 2.82
January 2004	287,425	$ 5.27

Pro Forma Effect on Net Income (Loss). In accordance with SFAS No. 123, the Company applies the intrinsic value method contained in APB No. 25 and discloses the required pro forma effect on net income (loss) as if the fair value method of accounting for stock compensation was used. The weighted average grant date fair value for an option to purchase Reliant Resources common stock granted during 2001, 2002 and 2003 was $13.35, $5.09 and $3.10, respectively. The weighted average grant date fair value of a purchase right issued under Reliant Resources ESPP during 2001, 2002 and 2003 was $9.24, $4.51 and $1.80, respectively. The weighted average grant date fair value for an option to purchase CenterPoint common stock granted during 2001 was $9.25.

The fair values were estimated using the Black-Scholes option valuation model with the following weighted average assumptions:

	Reliant Resources Stock Options		
	2001	2002	2003
Expected life in years	5	5	5
Risk-free interest rate	4.94%	4.43%	2.75%
Estimated volatility	42.65%	46.99%	113.64%
Expected common stock dividend	0%	0%	0%

	Reliant Resources Purchase Rights Under ESPP		
	2001	2002	2003
Expected life in months	8	6	6
Risk-free interest rate	3.92%	1.89%	1.18%
Estimated volatility	46.48%	71.32%	110.73%
Expected common stock dividend	0%	0%	0%

	CenterPoint Stock Options 2001
Expected life in years	5
Risk-free interest rate	4.87%
Estimated volatility of CenterPoint common stock	31.91%
Expected common stock dividend	5.75%

For 2001 and 2002, stock option expected volatility was determined based on an average of the historical volatility of Reliant Resources common stock and a group of companies considered similar to Reliant Resources. For 2003, stock option expected volatility was determined based on the historical volatility of Reliant Resources common stock. The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options, which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because Reliant Resources employee stock options and purchase rights have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in Reliant Resources' opinion, the existing models do not necessarily provide a single measure of the fair value of employee stock options and purchase rights.

For the pro forma computation of net income (loss) as if the fair value method of accounting had been applied to all stock awards, see note 2(h).

(b) Pension.

Prior to March 1, 2001, certain of the Company's employees participated in CenterPoint's noncontributory cash balance pension plan. Effective March 1, 2001, Reliant Resources and its subsidiaries no longer accrued benefits under this noncontributory pension plan for their domestic non-union employees (Resources Participants). Effective March 1, 2001, each Resources Participant's unvested pension account balance became fully vested and a one-time benefit enhancement was provided to some qualifying participants.

The retirement plan provides retirement benefits based on years of service and compensation. CenterPoint's funding policy was to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Prior to the Distribution, pension (expense) income was allocated to the Company based on the number of the Company's employees with an accrued benefit. Assets of the retirement plan are not segregated or restricted by CenterPoint's participating subsidiaries and accrued obligations for the Company employees are the obligation of the retirement plan. The Company's pension income was approximately $1 million for 2001 and 2002.

(c) Savings Plan.

The savings plan is a tax-qualified plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and includes a cash or deferred arrangement under Section 401(k) of the Code for the Company's employees. Prior to February 1, 2002, Reliant Resources' non-union employees participated in CenterPoint's employee savings plan that is a tax qualified plan under Section 401(a) of the Code, and included a cash or deferred arrangement under Section 401(k) of the Code.

Under the plan, participating employees may contribute a portion of their compensation, pre-tax or after-tax, generally up to a maximum of 16% of compensation. The savings plan's matching contribution

and any payroll period discretionary employer contribution will be made in cash; any discretionary annual employer contribution, as applicable, may be made in Reliant Resources common stock, cash or both.

The savings plans benefit expense was $2 million, $4 million and $9 million in 2001, 2002 and 2003, respectively.

(d) Postretirement Benefits.

Historically, the Company provided some postretirement benefits through CenterPoint plans (primarily medical care and life insurance benefits) for its retired employees, substantially all of whom may become eligible for these benefits when they retire. SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," requires that the expected cost of employees' postretirement benefits, be charged to income during the years in which employees render service. The Company's postretirement benefit costs were less than $1 million for 2001 and 2002. There were no postretirement benefit costs in 2003.

(9) Income Taxes

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

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Current			
Federal	$(24.8)	$217.7	$242.7
State	—	30.7	38.2
Total current	(24.8)	248.4	280.9
Deferred			
Federal	17.2	(40.9)	(41.8)
State	—	(2.4)	(7.5)
Total deferred	17.2	(43.3)	(49.3)
Income tax (benefit) expense	$ (7.6)	$205.1	$231.6

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

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
(Loss) income before income taxes	$(22.3)	$533.2	$603.8
Federal statutory rate	35%	35%	35%
Income tax (benefit) expense at statutory rate	(7.8)	186.6	211.3
Net addition in taxes resulting from:			
State income taxes, net of federal income tax benefit	—	18.4	20.0
Other, net	0.2	0.1	0.3
Total	0.2	18.5	20.3
Income tax (benefit) expense	$ (7.6)	$205.1	$231.6
Effective rate	33.8%	38.5%	38.4%

Following were the Company's tax effects of temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their respective tax bases:

	December 31,	
	2002	2003
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$13.4	$14.6
Accrual for payment to CenterPoint Energy, Inc.	—	66.8
Other	0.1	—
Total current deferred tax assets	13.5	81.4
Non-current:		
Employee benefits	1.0	5.2
Accrual for payment to CenterPoint Energy, Inc.	48.7	—
Other	0.2	0.8
Total non-current deferred tax assets	49.9	6.0
Total deferred tax assets	$63.4	$87.4
Deferred tax liabilities:		
Current:		
Trading and derivative assets, net, including affiliate	$23.4	$17.0
Total current deferred tax liabilities	23.4	17.0
Non-current:		
Depreciation and amortization	10.7	28.3
Trading and derivative assets, net, including affiliate	4.3	2.5
Total non-current deferred tax liabilities	15.0	30.8
Total deferred tax liabilities	$38.4	$47.8
Accumulated deferred income taxes, net	$25.0	$39.6

(10) Commitments

(a) Lease Commitments.

The following table sets forth information concerning the Company's cash obligations under non-cancelable long-term operating leases as of December 31, 2003, which primarily relate to rental agreements for building space and data processing equipment (in millions):

2004	$ 4
2005	4
2006	4
2007	3
2008	2
2009 and thereafter	4
Total	$21

Total lease expense for all operating leases during 2001, 2002 and 2003 was $7 million, $4 million and $5 million, respectively.

(b) Guarantees.

Together with certain of Reliant Resources' other subsidiaries, the Company is a guarantor of the obligations under Reliant Resources' Amended and Restated Credit and Guaranty Agreement dated as of March 28, 2003, and of the obligations under Reliant Resources' senior secured notes issued in July 2003. All of the Company's subsidiaries, except for RE Retail Receivables, LLC also guarantee Reliant Resources' obligations under Amended and Restated Credit and Guaranty Agreement and its senior secured notes. The Company's maximum potential amount of future payments under the guarantee is approximately $1.1 billion. Reliant Resources' obligations mature at various dates from 2010 through 2013.

Both Reliant Resources' March 2003 credit facility and its senior secured notes restrict the Company's ability to take specific actions, subject to numerous exceptions that are designed to allow for the execution of Reliant Resources' and its subsidiaries' business plans in the ordinary course, including the preservation and optimization of existing investments and the ability to provide credit support for commercial obligations.

(c) Other Commitments.

Purchase Power and Electric Capacity Commitments. The Company is a party to several purchase power and electricity capacity contracts, that have various quantity requirements and durations that are not classified as derivatives assets and liabilities and hence are not included in the consolidated balance sheets as of December 31, 2003. Minimum purchase commitment obligations under these agreements are $609 million, $258 million and $61 million in 2004, 2005 and 2006, respectively. As of December 31, 2003, there are no such commitments after 2006.

The Company's aggregate minimum electric capacity commitments, including capacity auction products, are for 19,359 MW, 9,240 MW and 2,400 MW for 2004, 2005 and 2006, respectively. Included in the above purchase power and electric capacity commitments are amounts acquired from Texas Genco. For additional discussion of this commitment, see note 4.

As of December 31, 2003, the maximum duration under any individual purchased power and electric capacity contract is 3 years, with the exception of the contract to purchase wind power, which is 15 years, which is not a firm commitment to purchase power.

Sale Commitments. As of December 31, 2003, the Company has sale commitments, including electric energy and capacity sale contracts, which are not classified as trading and as derivative assets and liabilities and hence are not included in the consolidated balance sheets. At execution, the estimated minimum sale commitments under these contracts were $1.8 billion, $610 million, $120 million and $5 million in 2004, 2005, 2006 and 2007, respectively. As of December 31, 2003, there are no such commitments after 2007.

In addition, in January 2002, the Company began providing retail electric services to approximately 1.7 million residential and small commercial customers previously served by CenterPoint's electric utility division. In the Houston area, the Texas electric restructuring law required the Company, as a former affiliate of the transmission and distribution utility in Houston, to sell electricity to residential or small commercial customers only at a specified price, or "price-to-beat" until the earlier of January 1, 2005, or the date that 40% or more of the electric power consumed by the applicable customer class is served by other retail electric providers. In January 2004, the PUCT made such a determination for small commercial customers and the Company is now permitted to sell electricity at unregulated prices both outside and in the Houston area for these customers. The Company does not expect to meet the 40% test for its residential customers in the Houston area. The price-to-beat was the only price that could be offered by the Company to residential and small commercial customers in the Houston area throughout 2003. The Texas electric restructuring law requires the Company to continue to make electricity available for its small commercial customers in the Houston area at the price-to-beat until January 1, 2007. The PUCT's regulations allow the Company to adjust its price-to-beat fuel factor based on a percentage change in the price of natural gas. In addition, the Company may also request an adjustment as a result of changes in the price of purchased energy. The Company can request up to two adjustments to its price-to-beat in each year. During 2002 and 2003, the Company requested and the PUCT approved two such adjustments in each year.

For information regarding commitments to CenterPoint and commitments to affiliates, see note 3.

Other Commitments. In addition to items discussed in the consolidated financial statements, the Company's other contractual commitments have various quantity requirements and durations and are not considered material either individually or in the aggregate to the results of operations or cash flows.

(11) Contingencies

(a) Legal Matters.

Regulatory Investigations. In connection with the PUCT's industry-wide investigation into potential manipulation of the ERCOT market, Reliant Energy Services provided information to the PUCT concerning its scheduling and trading practices on and after July 31, 2001. Reliant Energy Services reached a settlement relating to scheduling issues. The PUCT approved the settlement in November 2002. The costs of the settlement, $3 million, were transferred from Reliant Energy Services to the Company in December 2002.

Texas Commercial Energy. In July 2003, Texas Commercial Energy, LLP filed a lawsuit against the Company and several other participants in the ERCOT power market in the Corpus Christi Federal District Court for the Southern District of Texas. The plaintiff, a retail electricity provider in the ERCOT market, alleges that the defendants committed violations of state and federal antitrust laws, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract and civil conspiracy. The lawsuit seeks damages in excess of $535 million, exemplary damages, treble damages, interest, costs of suit and attorneys' fees. In November 2003, two other retail electric providers in the ERCOT market requested to intervene in this action as plaintiffs making factual allegations similar to those made by Texas Commercial Energy, LLP and seeking the same kinds of relief, although not specifying the amount of damages they

seek. The intervention motion and the motions to dismiss Texas Commercial Energy, LLP's complaint are set for hearing in May 2004.

PUCT Cases. Since 2002, the PUCT has approved various increases to the fuel factor component contained in our "price-to-beat." Parties opposing the increases have filed for judicial review of the PUCT's orders in state district court in Travis County, Texas. To date, the court has affirmed the first PUCT ruling. While the other rulings are pending at the district court, the parties opposing the increases, have appealed the district court's decision. In each of these proceedings we are vigorously contesting the appeal.

Other Matters. The Company is involved in other legal proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Although the Company cannot predict the outcome of these proceedings, the Company believes that the effects on the financial statements, if any, from the disposition of these matters will not have a material adverse effect on the results of operations, financial condition or cash flows.

(12) Receivables Facility

In July 2002, the Company entered into a receivables facility arrangement with a financial institution to sell an undivided interest in the Company's accounts receivable from residential and small commercial retail electric customers under which, on an ongoing basis, the financial institution could invest a maximum of $250 million for its interest in eligible receivables. This facility was amended in September 2003 to include a second financial institution, to include the accounts receivable from the Company's large commercial, industrial and institutional customers and to increase the facility to a maximum total of $350 million. The sale of accounts receivable is reflected as a decrease in accounts and notes receivable, principally customers, and unbilled revenues, net and an increase in notes receivable related to receivables facility on the consolidated balance sheets. Pursuant to the receivables facility, the Company formed a QSPE as a bankruptcy remote subsidiary. The QSPE was formed for the sole purpose of buying receivables generated by the Company and selling undivided interests to the financial institutions. The QSPE is a separate entity and its assets will be available first and foremost to satisfy the claims of its creditors. The Company, irrevocably and without recourse, transfers receivables to the QSPE. The QSPE, in turn, sells an undivided interest in these receivables to the participating financial institutions. The Company is not ultimately liable for any failure of payment of the obligors on the receivables. Reliant Resources has, however, guaranteed the performance obligations of the sellers and the servicing of the receivables under the related documents.

The amount of accounts receivable included under the arrangement may increase as certain accounts receivable become eligible, particularly from some of the large commercial, industrial, and institutional customers, and result in additional available funding. There can be no assurance that these accounts receivable will become eligible and result in additional available funding.

The two-step transaction described above is accounted for as a sale of receivables, which is recorded after the first step, and as a result the related receivables are excluded from the consolidated balance sheets. The Company continues to service the receivables and receive a fee of 0.5% of cash collected. The net costs associated with the sale of receivables since the inception of the facility are $8 million.

The following table details the outstanding receivables that have been sold and the corresponding notes receivable from the QSPE, which have been reflected in the Company's consolidated balance sheets:

	December 31,	
	2002	2003
	(In millions)	
Accounts receivable sold	$ 277	$ 528
Notes receivable from QSPE	(168)	(394)
Equity contributed to QSPE	(8)	(16)
Other accounts receivable from QSPE	(6)	—
Funding outstanding	$ 95	$ 118

The failure of the obligors to make payment on the receivables could result in the Company's notes receivable from the QSPE not being fully realized. Texas Genco holds a senior lien on these notes receivable, while Reliant Resources' senior secured note holders and the banks under Reliant Resources' March 2003 credit facilities ratably hold a junior lien. See note 4 for further discussion.

The amount of funding available under the receivables facility fluctuates based on the amount of eligible receivables available and by the performance of the receivables portfolio.

The following table details the maximum amount under the receivables facility and the amount of funding outstanding as of December 31, 2002 and 2003:

	December 31,	
	2002	2003
	(In millions)	
Maximum amount under the receivables facility	$ 200	$ 350
Funding outstanding	(95)	(118)
Unused and unavailable amount	$ 105	$ 232

Prior to their sale, the book value of the accounts receivable is offset by the amount of the allowance for doubtful accounts and customer security deposits. In calculating the loss on sale for 2002 and 2003, an average discount rate of 5.40% and 8.40%, respectively, was applied to projected cash collections over a 6-month period. The Company's collection experience indicated that 98% of the accounts receivables would be collected within a 6-month period.

The receivables facility expires on September 28, 2004. If the receivables facility is not renewed on its termination date, the collections from the receivables purchased will repay the financial institutions' investment and no new receivables will be purchased under the receivables facility.

(13) Estimated Fair Value of Financial Instruments

The fair values of financial instruments, including cash and cash equivalents, short-term and long-term borrowings, and trading and derivative assets and liabilities, are equivalent to their carrying amounts in the consolidated balance sheets. The fair values of trading and derivative assets and liabilities as of December 31, 2002 and 2003 have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques. See note 6.

* * *

INDEX TO FINANCIAL STATEMENTS

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC AND SUBSIDIARIES

Independent Auditors' Report F-149
Consolidated Statements of Operations for the Years Ended December 31, 2001, 2002 and 2003 . . F-150
Consolidated Balance Sheets as of December 31, 2002 and 2003 . . . . . F-151
Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2002 and 2003 F-152
Consolidated Statements of Shareholder's Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2001, 2002 and 2003 . . . . . F-153
Notes to Consolidated Financial Statements F-154

INDEPENDENT AUDITORS' REPORT

To Reliant Energy Mid-Atlantic Power Holdings, LLC
Houston, Texas

We have audited the accompanying consolidated balance sheets of Reliant Energy Mid-Atlantic Power Holdings, LLC and subsidiaries (the "Company") as of December 31, 2002 and 2003, and the related consolidated statements of operations, shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2002 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in notes 2 and 4 to the consolidated financial statements, the Company changed its accounting for asset retirement obligations and its presentation of revenues and cost of sales associated with non-trading commodity derivative activities in 2003; goodwill and other intangibles in 2002; and derivative contracts and hedging activities in 2001.

DELOITTE & TOUCHE LLP

Houston, Texas
March 5, 2004

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2001	2002	2003
	(Thousands of dollars)		
Revenues, including $80.3 million, $65.2 million and $48.4 million from affiliate, respectively	$577,037	$604,716	$594,373
Expenses:			
Fuel and purchased power, including $22.2 million, $36.9 million and $16.8 million from affiliate, respectively	173,814	208,647	204,945
Operation and maintenance	131,282	112,125	121,879
Facilities leases	59,649	60,117	59,847
General and administrative	10,984	10,340	8,821
General and administrative from affiliates	70,288	79,291	92,196
Depreciation	36,303	51,962	51,311
Amortization	14,210	14,761	28,554
Total	496,530	537,243	567,553
Operating Income	80,507	67,473	26,820
Other Income (Expense):			
Interest expense to affiliate	(88,989)	(84,965)	(60,729)
Interest expense	(1,416)	(962)	(1,601)
Interest income	2,093	2,059	554
Other income	2,825	1,284	4,032
Total other expense	(85,487)	(82,584)	(57,744)
Loss Before Income Taxes and Cumulative Effect of Accounting Change	(4,980)	(15,111)	(30,924)
Income tax benefit	(4,540)	(7,542)	(15,692)
Loss Before Cumulative Effect of Accounting Change	(440)	(7,569)	(15,232)
Cumulative effect of accounting change, net of tax	—	—	2,305
Net Loss	$ (440)	$ (7,569)	$(12,927)

See Notes to the Consolidated Financial Statements

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2003
	(Thousands of dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 42,052	$ 43,342
Restricted cash	—	14,078
Accounts receivable	4,670	5,909
Accounts receivable from affiliates	56,968	36,178
Fuel stock and petroleum products	34,371	31,516
Materials and supplies	42,094	43,770
Prepaid leases	59,030	59,030
Derivative assets	63,416	64,614
Other	4,367	4,243
Total current assets	306,968	302,680
Property, Plant and Equipment, net	822,335	792,532
Other Assets:		
Goodwill, net	6,808	3,853
Other intangibles, net	184,953	157,808
Derivative assets	32,805	10,683
Restricted cash	—	28,260
Prepaid leases	200,052	217,781
Accumulated deferred income taxes, net	—	4,939
Other	23,214	28,761
Total other assets	447,832	452,085
Total Assets	$1,577,135	$1,547,297
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities:		
Current portion of long term debt	$ —	$ 14,069
Accounts payable	17,206	15,538
Subordinated accounts payable to affiliates	107,920	168,296
Subordinated interest payable to affiliates, net	232,911	233,267
Derivative liabilities	43,609	62,869
Accrued payroll	4,787	3,204
Income taxes payable	649	313
Accumulated deferred income taxes, net	8,188	721
Other	9,957	8,957
Total current liabilities	425,227	507,234
Other Liabilities:		
Accrued environmental liabilities	34,693	23,056
Derivative liabilities	24,358	38,456
Accumulated deferred income taxes, net	39,476	23,464
Other	13,112	21,756
Total other liabilities	111,639	106,732
Subordinated Notes Payable to Affiliate	685,597	618,658
Long-term Debt	—	28,138
Total liabilities	1,222,463	1,260,762
Commitments and Contingencies		
Shareholder's Equity:		
Common stock (no par value, 1,000 shares authorized, issued and outstanding)	—	—
Additional paid-in capital	260,187	242,086
Retained earnings	73,207	60,280
Accumulated other comprehensive income (loss)	21,278	(15,831)
Total shareholder's equity	354,672	286,535
Total Liabilities and Shareholder's Equity	$1,577,135	$1,547,297

See Notes to the Consolidated Financial Statements

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2001	2002	2003
	(Thousands of dollars)		
Cash Flows from Operating Activities:			
Net loss	$ (440)	$ (7,569)	(12,927)
Adjustments to reconcile net loss to net cash (used in) provided by operating activities:			
Cumulative effect of accounting change	—	—	(2,305)
Depreciation and amortization	50,513	66,723	79,865
Deferred income taxes	19,991	(59,468)	(3,896)
Net derivative assets and liabilities	54,457	(64,592)	(12,098)
Federal income tax contribution from Reliant Resources, Inc.	—	45,150	(18,101)
Changes in assets and liabilities:			
Restricted cash	—	—	(42,338)
Accounts receivable	5,159	55	(1,239)
Accounts receivable from affiliates	3,344	(21,713)	20,790
Fuel stock and petroleum products and materials and supplies	(24,121)	12,152	1,179
Prepaid leases	(180,531)	(78,551)	(17,727)
Net derivative assets and liabilities	(54,592)	247,649	3,124
Other current assets	54,725	(2,066)	124
Other assets	(14,709)	2,575	(24,481)
Accounts payable	(42,166)	(2,522)	(1,668)
Taxes payable/receivable	(17,333)	13,282	(336)
Subordinated accounts payable to affiliates	24,253	30,356	60,376
Subordinated interest payable to affiliates, net	88,989	70,885	356
Other current liabilities	(18,257)	2,941	(2,583)
Other liabilities	6,626	2,903	2,951
Net cash (used in) provided by operating activities	(44,092)	258,190	29,066
Cash Flows from Investing Activities:			
Purchases of property, plant and equipment	(12,558)	(36,630)	(22,259)
Proceeds from sale of permits and licenses to affiliate	—	—	19,215
Net cash used in investing activities	(12,558)	(36,630)	(3,044)
Cash Flows from Financing Activities:			
Proceeds from subordinated notes payable to affiliate	188,881	13,000	—
Payments on subordinated notes payable to affiliate	(2,621)	(360,225)	(66,939)
Proceeds from long term debt	—	—	42,207
Net cash provided by (used in) financing activities	186,260	(347,225)	(24,732)
Net Change in Cash and Cash Equivalents	129,610	(125,665)	1,290
Cash and Cash Equivalents at Beginning of Period	38,107	167,717	42,052
Cash and Cash Equivalents at End of Period	$ 167,717	$ 42,052	$ 43,342
Supplemental Disclosure of Cash Flow Information:			
Cash payments:			
Interest paid to affiliate	$ —	$ 13,766	$ 60,634
Interest paid to third-party	1,218	805	1,611
Income taxes (net of income tax refunds received)	51,866	596	6,637

See Notes to the Consolidated Financial Statements

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)

	Common Stock (Shares)	Common Stock (Amount)	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholder's Equity	Comprehensive Income (Loss)
				(Thousands of dollars)			
Balance at December 31, 2000	1,000	$—	$111,245	$81,216	$ —	$192,461	
Net loss				(440)		(440)	$ (440)
Contribution of net derivative assets, net of tax of $75 million			103,359			103,359	
Other capital contributions			433			433	
Cumulative effect of adoption of SFAS No. 133, net of tax of $41 million					(73,643)	(73,643)	(73,643)
Deferred gain from cash flow hedges, net of tax of $95 million					151,655	151,655	151,655
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $9 million					(13,057)	(13,057)	(13,057)
Comprehensive income							$ 64,515
Balance at December 31, 2001	1,000	—	215,037	80,776	64,955	360,768	
Net loss				(7,569)		(7,569)	$ (7,569)
Capital contributions			45,150			45,150	
Deferred loss from cash flow hedges, net of tax of $20 million					(29,517)	(29,517)	(29,517)
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $10 million					(14,160)	(14,160)	(14,160)
Comprehensive loss							$(51,246)
Balance at December 31, 2002	1,000	—	260,187	73,207	21,278	354,672	
Net loss				(12,927)		(12,927)	$(12,927)
Distributions			(18,101)			(18,101)	
Deferred loss from cash flow hedges, net of tax of $23 million					(33,317)	(33,317)	(33,317)
Reclassification of net deferred gain from cash flow hedges into net loss, net of tax of $3 million					(3,792)	(3,792)	(3,792)
Comprehensive loss							$(50,036)
Balance at December 31, 2003	1,000	$—	$242,086	$60,280	$(15,831)	$286,535	

See Notes to the Consolidated Financial Statements

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background

Reliant Energy Mid-Atlantic Power Holdings, LLC and subsidiaries (REMA), is an indirect wholly owned subsidiary of Reliant Energy Power Generation, Inc. (REPG). REPG is a wholly owned subsidiary of Reliant Resources, Inc. (Reliant Resources).

As of December 31, 2003, REMA owned or leased interests in 20 operating electric generation plants in Pennsylvania, New Jersey and Maryland with an annual average net generating capacity of approximately 3,798 megawatts (MW). See note 12.

(2) Summary of Significant Accounting Policies

(a) Reclassifications.

Some amounts from the previous years have been reclassified to conform to the 2003 presentation of financial statements. These reclassifications do not affect earnings.

(b) Use of Estimates and Market Risk and Uncertainties.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. REMA's critical accounting estimates include: (a) property, plant and equipment, (b) depreciation expense, (c) derivative activities, (d) contingencies and (e) deferred tax asset valuation allowances and tax liabilities.

REMA is subject to risks associated with price movements of energy commodities and the credit risk associated with its commercial activities. For additional information regarding these risks, see notes 2(d) and 5. REMA is subject to risks relating to the reliability of the systems, procedures and other infrastructure necessary to operate its business. REMA is also subject to risks relating to changes in laws and regulations; the effects of competition; liquidity concerns in the markets in which REMA operates; the availability of adequate supplies of fuel and transportation; weather conditions; financial market conditions and REMA's access to capital; the creditworthiness or financial distress of REMA's counterparties; actions by rating agencies with respect to REMA or its competitors; political, legal, regulatory and economic conditions and developments; the successful operation of deregulating power markets and other items.

(c) Principles of Consolidation.

REMA's accounts and those of its wholly-owned subsidiaries are included in the consolidated financial statements. All significant intercompany transactions and balances are eliminated in consolidation.

In 2000, REMA entered into separate sale-leaseback transactions with each of three owner-lessors for its respective interests in three power generation stations (see note 9(a)). REMA does not consolidate these generating facilities.

In January 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51," (FIN No. 46). The objective of FIN No. 46 is to achieve more consistent application of consolidation policies to variable interest entities and to improve comparability between enterprises engaged in similar activities. FIN No. 46 states that an enterprise must consolidate a variable interest entity if the enterprise has a variable interest that will absorb a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both. FIN No. 46 requires entities to either (a) record the effects

prospectively with a cumulative effect adjustment as of the date on which FIN No. 46 is first applied or (b) restate previously issued financial statements for the years with a cumulative effect adjustment as of the beginning of the first year being restated.

REMA adopted FIN No. 46 on January 1, 2003. FIN No. 46 did not have any impact on REMA's consolidated financial statements. In December 2003, the FASB released FASB Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51" (FIN No. 46R), which replaces FIN No. 46 and modified certain criteria in determining which entities should be considered as variable interest entities. REMA does not believe the application of FIN No. 46R will have a material impact to its consolidated financial statements. The application of FIN No. 46R continues to evolve as the FASB continues to address issues submitted for consideration. REMA will continue to assess its application of clarified or revised guidance related to FIN No. 46R.

(d) Revenues and Accounting for Hedging Activities.

Power Generation Revenues. Revenues include energy, capacity and ancillary service sales. REMA records gross revenues under the accrual method and these revenues generally are recognized upon delivery. REMA's electric power and services are sold at market-based prices through a related party and indirect subsidiary of Reliant Resources, Reliant Energy Services, Inc. (Reliant Energy Services). Reliant Energy Services acts as agent on behalf of REMA on most market-based sales. REMA's capacity was also sold pursuant to a transition power purchase agreement with GPU, Inc.. The transition power purchase agreement expired on May 31, 2002. Sales not billed by month-end are accrued based upon estimated energy or services delivered. See below for the discussion of the impact of implementation of Emerging Issues Task Force (EITF) Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" As Defined in EITF Issue No. 02-03" (EITF No. 03-11).

Hedging Activities. Effective January 1, 2001, REMA adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133), which establishes accounting and reporting standards for derivative instruments. Adoption of SFAS No. 133 on January 1, 2001 resulted in no after-tax increase in net income and a cumulative after-tax increase in accumulated other comprehensive loss of $73.6 million. During 2001, $70.4 million of the initial after-tax transition adjustment recorded in accumulated other comprehensive loss was recognized in net loss.

If certain conditions are met, REMA may designate a derivative instrument as hedging (a) the exposure to variability in expected future cash flows (cash flow hedge), (b) the exposure to changes in the fair value of an asset or liability (fair value hedge) or (c) the foreign currency exposure of a net investment in a foreign operation. This statement requires that a derivative be recognized at fair value in the balance sheet whether or not it is designated as a hedge. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are designated as normal purchases and sales exceptions and are not reflected in REMA's consolidated balance sheets at fair value. For a derivative that is designated as a cash flow hedge, and depending on its effectiveness, changes in fair value are deferred as a component of accumulated other comprehensive income (loss), net of applicable taxes.

REMA designates its derivatives utilized in non-trading activities as cash flow hedges only if there is a high correlation between price movements in the derivative and the item designated as being hedged. This correlation is measured both at the inception of the hedge and on an ongoing basis, with an acceptable level of correlation of at least 80% to 125% for hedge designation. The gains and losses related to derivative instruments designated as cash flow hedges are deferred in accumulated other comprehensive

income (loss), net of tax, to the extent the contracts are effective as hedges, and then are recognized in REMA's results of operations in the same period as the settlement of the underlying hedged transactions. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive income (loss) is reclassified and included in our consolidated statements of operations (a) prior to October 1, 2003, under the captions (i) fuel and purchased power, in the case of hedging activities related to physical and financial natural gas transactions and (ii) revenues, in the case of hedging activities related to physical and financial power transactions and (b) effective October 1, 2003, under the captions (i) fuel and purchased power, in the case of hedging activities related to physical natural gas purchase transactions, physical natural gas sales transactions that do not physically flow, financial natural gas transactions and physical power purchase transactions that physically flow, and (ii) revenues, in the case of hedging activities related to financial power transactions, physical power sales transactions, physical power purchase transactions that do not physically flow and natural gas sales transactions that physically flow.

For a derivative not designated as a hedge, changes in fair value are recorded as unrealized gains or losses in REMA's results of operations. If and when correlation ceases to exist at an acceptable level, hedge accounting ceases and changes in fair value are recognized currently in REMA's results of operations. If it becomes probable that a forecasted transaction will not occur, REMA immediately recognizes the respective deferred gains or losses in its results of operations. The associated hedging instrument is then marked to market through REMA's results of operations for the remainder of the contract term unless a new hedging relationship is redesignated.

In July 2003, the EITF issued EITF No. 03-11, which stated that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. On October 1, 2003, REMA began reporting prospectively the settlement of sales and purchases of fuel and power related to its hedging activities that were physically delivered on a gross basis in REMA's consolidated statement of operations. Prior to October 1, 2003 the settlement of sales and purchases of fuel and power related to REMA's hedging activities were reported on a net basis in REMA's consolidated statement of operations based on the item hedged. The application of EITF No. 03-11 did not result in a material impact on revenues and fuel and purchased power in REMA's consolidated statement of operations and is not expected to have a material impact on the presentation of future operations. EITF No. 03-11 has no impact on margins or net income. Comparative financial statements for prior periods have not been reclassified to conform to this presentation, as it is not required. In addition, it is not practicable to determine sales and purchases of fuel and purchased power in 2001, 2002 and the nine months ended September 30, 2003 that would have been shown net if EITF No. 03-11 had been applied to the results of operations historically.

In April 2003, the FASB issued SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 149 clarifies when a contract with an initial net investment meets the characteristics of a derivative and when a derivative contains a financing component, as discussed in SFAS No. 133. SFAS No. 149 also amends certain existing pronouncements, which will result in more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003 and should be applied prospectively. The implementation of SFAS No. 149 did not have a material impact on REMA's consolidated financial statements.

For additional discussion of derivative and hedging activities, see note 5.

Set-off of Derivative Assets and Liabilities. Where derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation No. 39, "Offsetting of Amounts Related to

Certain Contracts," are met, REMA presents its derivative assets and liabilities on a net basis in the consolidated balance sheets. Derivative assets/liabilities and accounts receivable/payable are presented separately in the consolidated balance sheets. The derivative assets/liabilities and accounts receivable/payable are set-off separately in the consolidated balance sheets although in certain cases contracts permit the set-off derivative assets/liabilities and accounts receivable/payable with a given counterparty.

(e) General and Administrative Expense.

The general and administrative expenses from affiliates include an allocation of corporate and administrative services, insurance and utility costs (including management services, financial and accounting, cash management and treasury support, legal, information technology system support, office management and human resources) under REMA's support services agreement with REPG (see note 3(b)).

(f) Property, Plant and Equipment and Depreciation Expense.

REMA records property, plant and equipment at historical cost. REMA expenses all repair and maintenance costs as incurred, including planned major maintenance. Depreciation is computed using the straight-line method based on estimated useful lives. Property, plant and equipment includes the following:

	Estimated Useful Lives (Years)	December 31, 2002	December 31, 2003
		(In thousands)	
Electric generation facilities	10 - 30	$824,926	$ 803,734
Building and building improvements(1)	9 - 30	9,118	1,860
Land improvements	15 - 33	9,020	42,016
Other	3 - 10	4,883	4,511
Land		31,069	29,113
Assets under construction		36,132	22,175
Total		915,148	903,409
Accumulated depreciation		(92,813)	(110,877)
Property, plant and equipment, net		$822,335	$ 792,532

(1) Building and building improvements include the carrying value of the Johnstown office building which was written down by $6.5 million in 2003 to its fair value less costs to sell and is no longer being depreciated. See note 11.

REMA periodically evaluates property, plant and equipment for impairment when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. A resulting impairment loss is highly dependent on the underlying assumptions. During 2002, REMA recognized $15.0 million in depreciation expense for the early retirement of power generation units at its Warren facility. During 2003, REMA recorded the following charges in depreciation expense: $9.6 million for the early retirement of power generation units at its Sayreville facility and $6.5 million related to the write-down of an office building to its fair value less costs to sell (see note 11). As of December 31, 2003, REMA performed impairment analyses of certain of its property, plant and equipment. In addition, as of November 1, 2002 and July 1, 2003, REMA performed impairment analyses of all of its property, plant and equipment as it believed events had indicated that these assets may not be recoverable. Based on these analyses, REMA recorded no impairments.

If REMA's wholesale energy market outlook changes negatively, REMA could have impairments of property, plant and equipment in future periods. In addition, Reliant Resources' ongoing evaluation of its wholesale energy business could result in decisions to mothball, retire or dispose of additional generation assets, any of which could result in impairment charges. See note 12.

(g) Goodwill and Amortization Expense.

REMA records goodwill for the excess of the purchase price over the fair value assigned to the net assets of an acquisition. Through 2001, REMA amortized goodwill on a straight-line basis over 35 years. Pursuant to REMA's adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) on January 1, 2002, REMA discontinued amortizing goodwill. See note 4 for a discussion regarding REMA's adoption of SFAS No. 142. Goodwill amortization expense was $0.1 million for 2001. Amortization expense was for other intangibles $14.1 million, $14.8 million, and $28.6 million for 2001, 2002 and 2003, respectively. See also note 4.

REMA periodically evaluates goodwill and other intangibles when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. In 2001, the determination of whether an impairment had occurred was based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. Effective January 1, 2002, goodwill and other intangibles are evaluated for impairment in accordance with SFAS No. 142. To date, no impairment has been indicated. For further discussion of goodwill and other intangible impairment analyses in 2002 and 2003, see note 4.

(h) Income Taxes.

REMA uses the asset and liability method of accounting for deferred income taxes and measures deferred income taxes for all significant income tax temporary differences. For additional information regarding income taxes, see note 8.

From the date of REMA's acquisition by Reliant Resources through September 30, 2002, REMA was included in the consolidated income tax return of CenterPoint Energy, Inc. (CenterPoint Energy), formerly the majority owner of Reliant Resources. As of October 1, 2002, REMA is included in the consolidated tax returns of Reliant Resources and calculates its income tax provision on a separate return basis, whereby Reliant Resources pays all federal income taxes on REMA's behalf and is entitled to any related tax savings. The difference between REMA's current federal income tax expense or benefit, as calculated on a separate return basis, and related amounts paid or received to/from Reliant Resources, if any, is recorded as adjustments to additional paid-in capital on REMA's consolidated balance sheets.

(i) Cash.

REMA records as cash and cash equivalents all highly liquid short-term investments with original maturities or remaining maturities at the date of purchase of three months or less.

(j) Restricted Cash.

Restricted cash currently represents cash collateral posted to support REMA's lease obligations under its sale-leaseback transactions. See note 9(a). As of December 31, 2002 and 2003, REMA's current and long-term restricted cash totaled $0 and $42.3 million, respectively.

(k) Inventories.

Inventories consist of materials and supplies, including spare parts, coal, natural gas and heating oil. All inventory is valued at the lower of average cost or market.

(l) Environmental Costs.

REMA expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. REMA expenses amounts that relate to an existing condition caused by past operations and that do not have future economic benefit. REMA records liabilities related to expected future costs related to environmental assessments and/or remediation activities when they are probable and the costs can be reasonably estimated. See note 10(a) for further discussion.

(m) Asset Retirement Obligations.

On January 1, 2003, REMA adopted 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. Prior to the adoption of SFAS No. 143, REMA recorded asset retirement obligations in connection with certain business combinations. These obligations were recorded at their present values on the dates of acquisition. REMA's asset retirement obligations are primarily environmental obligations related to ash disposal site closures.

The impact of the adoption of SFAS No. 143 resulted in a gain of $2.3 million, net of tax of $1.6 million, as a cumulative effect of an accounting change in REMA's consolidated statement of operations for 2003. The impact of the adoption of SFAS No. 143 resulted in a January 1, 2003 cumulative effect of an accounting change to record (a) a $1.0 million increase in the carrying values of property, plant and equipment, (b) a $0.2 million increase in accumulated depreciation of property, plant and equipment, (c) a $3.1 million decrease in asset retirement obligations and (d) a $1.6 million increase in deferred income tax liabilities.

If REMA had adopted SFAS No. 143 on January 1, 2001, the impact would have been immaterial to its consolidated income from continuing operations and net income (loss) for both 2001 and 2002.

The following table presents the detail of REMA's asset retirement obligations, which are included in other long-term liabilities in its consolidated balance sheet (in millions):

Balance at January 1, 2003	$ 3.9
Accretion expense	0.2
Liabilities incurred	0.1
Payments	(3.9)
Balance at December 31, 2003	$ 0.3

(n) Deferred Lease Costs.

REMA incurred costs in connection with its sale-leaseback transactions in 2000 (see note 9(a)). These costs are deferred and amortized, using the straight-line method, over the life of the individual sale-leaseback transactions. REMA amortized $0.8 million to facilities lease expense in each of the years ended December 31, 2001, 2002 and 2003. As of December 31, 2002 and 2003, REMA had $22.9 million and

$22.1 million, respectively, of net deferred lease costs classified in other long-term assets in its consolidated balance sheets.

(o) Disclosures About Pensions and Other Postretirement Benefits.

In December 2003, the FASB issued a revision to SFAS No. 132, "Employers' Disclosures About Pensions and Other Postretirement Benefits — An Amendment of FASB Statements No. 87, 88 and 106" (SFAS No. 132 (Revised 2003)). This statement revises employers' disclosures about pension plans and other postretirement benefit plans. This statement retains the disclosure requirements contained in SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132), which it replaces. It requires additional disclosures to those in the original SFAS No. 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. REMA has adopted these additional disclosures. See note 7.

(p) New Accounting Pronouncements.

As of February 20, 2004, no standard setting body or authoritative body has established new accounting pronouncements or changes to existing accounting pronouncements that would have a material impact to REMA's results of operations, financial position or cash flows, for which REMA has not already adopted and/or disclosed elsewhere in these notes.

(3) Related Party Transactions

(a) Procurement and Marketing Agreement

REMA is a party to a procurement and marketing agreement with Reliant Energy Services under which Reliant Energy Services is entitled to procurement and power marketing fees. Under the agreement, Reliant Energy Services

- enters into derivative transactions on behalf of REMA to hedge commodity risks;
- procures coal, fuel oil and emissions allowances on REMA's behalf at a pass through price;
- procures gas on REMA's behalf at a pass through price or for an index price plus costs of delivery, depending on when and how the gas is procured; and
- markets power and surplus gas, fuel oil and emissions allowances on REMA's behalf.

The amount charged to REMA by Reliant Energy Services for these services was $4.6 million, $4.4 million and $4.7 million during 2001, 2002 and 2003, respectively. These amounts are classified in operation and maintenance expense in the consolidated statements of operations.

Fees charged under the procurement and marketing agreement are subordinated to certain payments pursuant to the sale-leaseback financing documents, including lease payments.

(b) Support Services Agreement

REMA is a party to a support services agreement with REPG under which REPG will, on an as-requested basis and at cost, provide or procure from other affiliates or third parties services in support of REMA's business in areas such as human resources, accounting, finance, treasury, tax, office administration, information technology, engineering, construction management, environmental, legal and safety. REPG has agreed to provide these services only to the extent it or its affiliates provide these services for it or its subsidiaries' generating assets. REPG charges and allocates costs to REMA for these

services. Amounts charged and allocated to REMA for these services were $70.3 million, $79.3 million and $92.2 million during 2001, 2002, and 2003, respectively. On January 1, 2003, REPG refined the methodology it used to allocate costs to REMA. The current method being used by REPG to allocate support service costs to REMA is based on REMA's direct labor costs relative to the direct labor costs of the other entities to which REPG provides similar services versus the prior method that was based on REMA's gross margin relative to the gross margin of the other entities to which REPG provides similar services. As a result of the change in allocation methodology, REMA has been allocated a higher percentage of costs than would have been allocated under the previous methodology. All of the allocations in the consolidated financial statements have been and continue to be based on assumptions that management believes are reasonable under the circumstances. However, these allocations may not necessarily be indicative of the costs and expenses that would have resulted if REMA had operated as a separate entity. These amounts are classified in general and administrative expense from affiliates in the consolidated statements of operations.

Costs charged under the support services agreement are subordinated to certain payments pursuant to the sale-leaseback financing documents, including lease payments.

(c) Subordinated Long-term Notes to Affiliated Entity

REMA has notes payable to Reliant Energy Northeast Holdings Inc. (RENH), a wholly-owned subsidiary of REPG. The notes are due January 1, 2029 and accrue interest at a fixed rate of 9.4% per annum. As of December 31, 2002 and 2003, REMA had $683.6 million and $618.7 million, respectively, outstanding under the notes. Payments under this indebtedness are subordinated to REMA's lease obligations.

In July 2001, REMA borrowed an additional $106.0 million from RENH. The borrowing would have matured on July 1, 2029, bore interest at a fixed rate of 9.4% and was unsecured. Repayment of the borrowing was subordinated to REMA's lease obligations as required by the lease documents. At December 31, 2002, $2.0 million of borrowings were outstanding under this note. The note was paid in full by REMA in March 2003.

(d) Working Capital Note

REMA has a revolving note payable to RENH under which REMA may borrow, and RENH is committed to lend, up to $30 million for working capital needs. Borrowings under the note will be unsecured and will rank equal in priority with REMA's lease obligations. REMA may replace this note with a working capital facility from an unaffiliated lender. Borrowings under the working capital note bear interest based on the London Inter-Bank Offered Rate (LIBOR). This note expires in May 2004. RENH plans to renew the working capital note prior to its expiration. At December 31, 2002 and 2003, there were no borrowings outstanding under this note.

(e) Subordinated Working Capital Facility

REMA entered into an irrevocably committed subordinated working capital facility with RENH. RENH will fund REMA's drawings under this facility through borrowings or equity contributions irrevocably committed to RENH by Reliant Resources. REMA may borrow under this facility to pay operating expenditures, senior indebtedness and rent, but excluding capital expenditures and subordinated indebtedness. In addition, RENH must make advances to REMA and REMA must obtain such advances under such facility up to the maximum available commitment under such facility from time to time if REMA's pro forma coverage ratio does not equal or exceed 1.1 to 1.0, measured at the time rent under the leases is due. Subject to the maximum available commitment, drawings will be made in amounts

necessary to permit REMA to achieve a pro forma coverage ratio of at least 1.1 to 1.0. The amount available under the subordinated working capital facility is $120.0 million through January 1, 2007. Thereafter, the available amount decreases by $24.0 million on January 2, 2007 and by $24.0 million each subsequent year through its expiration in 2011. At December 31, 2002 and 2003, there were no borrowings outstanding under this facility.

(4) Goodwill and Intangibles

In July 2001, the FASB issued SFAS No. 142, which states that goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and charged to results of operations in periods in which the recorded value of goodwill and certain intangibles with indefinite lives exceeds their fair values. REMA adopted the provisions of the statement effective January 1, 2002, and discontinued amortizing goodwill into its results of operations. A reconciliation of 2001 reported net loss adjusted for the exclusion of goodwill amortization with a comparison of 2002 and 2003 follows:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Reported net loss	$(0.4)	$(7.6)	$(12.9)
Add: Goodwill amortization, net of tax	0.1	—	—
Adjusted net loss	$(0.3)	$(7.6)	$(12.9)

Intangibles. Other intangible assets consist of the following:

	Weighted-Average Amortization Period (Years)	December 31,			
		2002		2003	
		Carrying Amount	Accumulated Amortization	Carrying Amount	Accumulated Amortization
		(In millions)			
Air emission regulatory allowances	35	$177.3	$(32.1)	$197.6	$(59.4)
Power generation site permits and water rights	35	43.0	(3.2)	21.9	(2.3)
Total		$220.3	$(35.3)	$219.5	$(61.7)

REMA recognizes specifically identifiable intangibles, including air emissions regulatory allowances, power generation site permits, and water rights when acquired. REMA has no intangible assets with indefinite lives recorded as of December 31, 2002 and 2003. REMA amortizes air emission regulatory allowances primarily on a units-of-production basis as utilized. REMA amortizes power generation site permits and water rights on a straight-line basis over their estimated useful lives. All intangibles, excluding goodwill, are subject to amortization.

Estimated amortization expense for the next five years is as follows (in millions):

2004	$15.3
2005	5.9
2006	4.9
2007	4.9
2008	4.8
Total	$35.8

During 2003, REMA sold certain power generation site permits and water rights to an affiliate for $19.2 million in cash. The permits and water rights were no longer needed for REMA's business. There was no gain or loss recorded on the sale. See note 12.

Goodwill. The following table shows the changes in the carrying amount of goodwill for 2002 and 2003 (in millions):

As of January 1, 2002	$ 4.6
Purchase adjustments(1)	2.2
As of December 31, 2002	6.8
Other(2)	(2.9)
As of December 31, 2003	$ 3.9

(1) In connection with the acquisition of REMA in 2000, REPG made an $8.2 million payment to the prior owner in the first quarter of 2002 for post-closing adjustments that resulted in a $2.2 million adjustment to REMA's goodwill.

(2) In connection with the acquisition of REMA in 2000, REMA recorded certain environmental liabilities associated primarily with ash disposal site closures and site contaminations (see note 10(a)). Upon further review in 2003, management determined that $2.9 million of the recorded environmental liabilities do not represent liabilities. As a result, goodwill was reduced by $2.9 million to reflect the reversal of these liabilities.

REMA has no goodwill that is deductible for United States income tax purposes.

During the second quarter of 2002, REMA completed the transitional impairment test as of January 1, 2002 for the adoption of SFAS No. 142 on its consolidated financial statements. This transitional impairment test resulted in no goodwill impairment at REMA.

SFAS No. 142 requires goodwill to be tested at least annually and more frequently in certain circumstances. The date of REMA's annual impairment test was November 1 for 2002 and 2003. In addition to the annual impairment tests, REMA tested its goodwill as of July 1, 2003 as a result of Reliant Resources' sale of the Desert Basin power generation plant, which required Reliant Resources to allocate a portion of the goodwill in the wholesale energy reporting unit to the Desert Basin plant operations on a relative fair value basis as of July 2003 in order to compute the gain or loss on disposal. SFAS No. 142 also required Reliant Resources to test the recoverability of goodwill in the remaining wholesale energy reporting unit as of July 2003. As a result of Reliant Resources' impairment analysis of its wholesale energy reporting unit, REMA tested the recoverability of its goodwill. Based on the July 1, 2003 test and the annual impairment tests, there was no impairment of goodwill during 2002 and 2003.

Potential Future Impairments of Goodwill. If REMA's wholesale energy market outlook changes negatively, REMA could have impairments of goodwill. In addition, Reliant Resources' ongoing evaluation of its business could result in decisions to mothball, retire or dispose of additional generation assets, any of

which could result in impairment charges related to goodwill, impact REMA's fixed assets' depreciable lives or result in fixed asset impairment charges. See note 12.

(5) Derivative Instruments

REMA is exposed to various market risks. These risks arise from the ownership of assets and operation of the business. REMA routinely utilizes 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 its operating results and cash flows.

Reliant Resources has a risk control framework, which REMA is subject to, designed to monitor, measure and define appropriate transactions to hedge and manage the risk in its existing portfolio of assets and contracts and to authorize new transactions. These risks fall into three different categories: market risk, credit risk and operational risk. REMA believes that it has effective procedures for evaluating and managing these risks to which it is exposed. Key risk control activities include definition of appropriate transactions for hedging, 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, value-at-risk and other risk measurement metrics. REMA seeks to monitor and control its risk exposures through a variety of separate but complementary processes and committees, which involve business unit management, senior management and Reliant Resources' board of directors.

The primary types of derivatives REMA uses are described below:

- Futures contracts are exchange-traded standardized commitments to purchase or sell an energy commodity or financial instrument, or to make a cash settlement, at a specific price and future date.
- Physical forward contracts are commitments to purchase or sell energy commodities in the future.
- Swap agreements require payments to or from counterparties based upon the differential between a fixed price and variable index price (fixed price swap) or two variable index prices (variable price swap) for a predetermined contractual notional amount. The respective index may be an exchange quotation or an industry pricing publication.
- Option contracts convey the right to buy or sell an energy commodity or a financial instrument at a predetermined price or settlement of the differential between a fixed price and a variable index price or two variable index prices.

To reduce the risk from market fluctuations in its results of operations and the resulting cash flows, REMA may enter into energy derivatives in order to hedge some expected natural gas and other commodities and sales of electric power. The derivative portfolios are managed to complement REMA's asset portfolio, reducing overall risks.

The fair values of REMA's derivative activities as of December 31, 2002 and 2003, are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

Below is the pre-tax income (loss) of REMA's derivative instruments, both from cash flow hedge ineffectiveness and from derivative mark-to-market income and losses, for 2001, 2002 and 2003:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Hedge ineffectiveness(1)	$ 0.1	$ 5.5	$(4.9)
Derivative mark-to-market (loss) income(2)	(1.1)	6.4	1.0
Total	$(1.0)	$11.9	$(3.9)

(1) For 2001, 2002 and 2003, no component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness.

(2) There were no amounts recognized in 2001, 2002 and 2003 in REMA's results of operations as a result of the discontinuance of cash flow hedges because it was probable that the forecasted transaction would not occur.

Below is a reconciliation of REMA's net derivative assets (liabilities) to accumulated other comprehensive income (loss), net of tax, as of December 31, 2002 and 2003:

	As of December 31,	
	2002	2003
	(In millions)	
Net derivative assets (liabilities)	$28.3	$(26.0)
Derivatives not designated as cash flow hedges	(5.3)	(6.3)
Recognized cash flow hedge ineffectiveness	(5.6)	(0.7)
Cash flow hedges terminated prior to maturity	18.8	5.9
Deferred tax (liabilities) assets attributable to accumulated other comprehensive income (loss) on cash flow hedges	(14.9)	11.3
Accumulated other comprehensive income (loss) from derivative instruments, net of tax(1)	$21.3	$(15.8)

(1) As of December 31, 2003, REMA expects $4.1 million of accumulated other comprehensive loss to be reclassified into its results of operations during 2004.

As of December 31, 2002 and 2003, the maximum length of time REMA is hedging its exposure to the variability in future cash flows for forecasted transactions, excluding the payment of variable interest on existing financial instruments, is ten years and nine years, respectively.

Other Derivative Activities. During 2001, Reliant Resources contributed derivative assets and liabilities to REMA as a result of four structured transactions involving a series of forward contracts to buy and sell an energy commodity in 2001 and to buy and sell an energy commodity in 2002. The change in fair value of these derivative assets and liabilities was recorded in the statement of consolidated operations for each reporting period. During 2001 and 2002, $54 million of net derivative liabilities and $248 million of net derivative assets, respectively, were settled related to these transactions, which was recorded in cash flows from operations; $8 million and $8 million, respectively, of pre-tax unrealized gains were recognized.

Credit Risk.

Credit risk is inherent in REMA's commercial activities and relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. Reliant Resources has broad credit policies and parameters, which REMA is subject to.

Reliant Energy Services enters into hedging and other transactions on behalf of REMA under its procurement and marketing agreement (see note 3(a)). Although Reliant Energy Services is the party to the contract, REMA maintains counterparty credit risk associated with the hedging and other transactions.

Reliant Energy Services seeks to enter into contracts on behalf of REMA that permit it to net receivables and payables with a given counterparty. Reliant Energy Services also enters into contracts that enable it to obtain collateral from a counterparty as well as to terminate upon the occurrence of certain events of default. The credit risk control organization establishes counterparty credit limits. Reliant Resources employs tiered levels of approval authority for counterparty credit limits, with authority increasing from the credit risk control organization through senior management. Credit risk exposure is monitored daily and the financial condition of REMA's counterparties is reviewed periodically.

If any of REMA's counterparties failed to perform, Reliant Energy Services might be forced to acquire alternative hedging arrangements on behalf of REMA or be required to replace the underlying commitment at then-current market prices. In this event, REMA might incur additional losses in addition to amounts owed to REMA by the counterparty. For information regarding the net provision recorded in 2001 related to energy sales to Enron, see note 10(a).

As of December 31, 2002, one investment grade counterparty represented 15% of REMA's total credit exposure, net of collateral. The dollar amount of REMA's credit exposure to this counterparty was $17.0 million as of December 31, 2002. As of December 31, 2002, there were no other counterparties representing greater than 10% of REMA's total credit exposure, net of collateral. As of December 31, 2003, one non-investment grade counterparty represented 18% of REMA's total credit exposure , net of collateral. The dollar amount of REMA's credit exposure to this counterparty was $13.9 million as of December 31, 2003. As of December 31, 2003, there were no other counterparties representing greater than 10% of REMA's total credit exposure, net of collateral.

(6) Long-term Debt

REMA is obligated to provide credit support for its lease obligations (see note 9(a)) in the form of letters of credit and/or cash resulting from draws on such letters of credit, equal to an amount representing the greater of (a) the next six months' scheduled rental payments under the related lease or (b) 50% of the scheduled rental payments due in the next 12 months under the related lease. REMA's lease obligations are currently supported by the cash proceeds resulting from the draw in August 2003 on three separate letters of credit and $16.3 million in letters of credit provided by Reliant Resources in January 2004. The draw on the letters of credit constituted the making of term loans to REMA by the banks that had issued the letters of credit pursuant to provisions that had been contemplated in the original letter of credit facilities at their inception and did not constitute a default under any of REMA's obligations. Interest on the term loans is payable at the rate of LIBOR plus 3%. REMA's subsidiaries guarantee REMA's obligations under the leases and the term loans.

(7) Retirement and Other Benefit Plans

(a) Pension.

During the first quarter of 2001, REMA's non-union employees participated in CenterPoint's noncontributory cash balance pension plan. Effective March 1, 2001, REMA no longer accrues benefits under this noncontributory pension plan for its non-union employees. Effective March 1, 2001, each non-union participant's unvested pension account balance became fully vested. Participants may elect to have their accrued benefits (a) left in the CenterPoint pension plan for which CenterPoint is the plan sponsor,

(b) rolled over to a savings plan or individual retirement account or (c) paid in a lump-sum or annuity distribution.

Substantially all of REMA's union employees participate in a noncontributory pension plan (the Union Pension Plan). The Union Pension Plan provides retirement benefits based on years of service and final average compensation. The funding policy is to review amounts annually in accordance with applicable regulations in order to determine contributions necessary to achieve adequate funding of projected benefit obligations. REMA uses a December 31 measurement date for its pension plan. REMA's pension and funded status are as follows:

	Year Ended December 31,	
	2002	2003
	(In thousands)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 6,558	$13,345
Service cost	3,354	3,861
Interest cost	474	896
Benefits paid	(43)	(177)
Special termination benefit	584	—
Actuarial loss (gain)	2,418	(273)
Benefit obligation, end of year	$13,345	$17,652
Change in Plan Assets		
Fair value of plan assets, beginning of year	$ 1,673	$ 4,247
Employer contributions	2,901	3,192
Actual investment return	(284)	1,127
Benefits paid	(43)	(177)
Fair value of plan assets, end of year	$ 4,247	$ 8,389
Reconciliation of Funded Status		
Funded status	$(9,098)	$(9,263)
Unrecognized actuarial loss	4,234	2,997
Net amount recognized, end of year	$(4,864)	$(6,266)

Amounts recognized in the consolidated balance sheets are as follows:

	December 31,	
	2002	2003
	(In thousands)	
Accrued benefit cost	$(4,864)	$(6,266)

The accumulated benefit obligation for the Union Pension Plan was $9.7 million and $13.1 million at December 31, 2002 and 2003, respectively.

Net pension cost includes the following components:

	Year Ended December 31,		
	2001	2002	2003
	(In thousands)		
Service cost — benefits earned during the period	$2,569	$3,354	$3,861
Interest cost on projected benefit obligation	198	474	896
Expected return on plan assets	(98)	(336)	(436)
Net amortization	31	53	273
Net pension cost	$2,700	$3,545	$4,594

The significant weighted average assumptions used to determine the pension benefit obligation include the following:

	December 31,	
	2002	2003
Discount rate	6.75%	6.25%
Rate of increase in compensation levels	4.5%	4.5%

The significant weighted average assumptions used to determine the net pension cost include the following:

	Year Ended December 31,		
	2001	2002	2003
Discount rate	7.5%	7.25%	6.75%
Rate of increase in compensation levels	3.5-5.5%	3.5-5.5%	4.5%
Expected long-term rate of return on assets	10.0%	9.5%	8.5%

As of December 31, 2003 REMA's expected long-term rate of return on pension plan assets is developed based on third party models. These models consider expected inflation, current dividend yields, expected corporate earnings growth and risk premiums based on the expected volatility of each asset category. The expected long-term rates of return for each asset category are weighted to determine the overall expected long-term rate of return on pension plan assets. In addition, peer data and historical returns are reviewed.

REMA's pension plan weighted average asset allocations at December 31, 2002 and 2003 and target allocation for 2004 by asset category are as follows:

	Percentage of Plan Assets at December 31,		Target Allocation
	2002	2003	2004
Domestic equity securities	55%	55%	55%
International equity securities	15	15	15
Debt securities	30	30	30
Total	100%	100%	100%

In managing the investments associated with the pension plans, the objective is to exceed, on a net-of-fee basis, the rate of return of a performance benchmark composed of the following indices:

Asset Class	Index	Weight
Domestic equity securities	Wilshire 5000 Index	55%
International equity securities	MSCI All Country World Ex-U.S. Index	15
Debt securities	Lehman Brothers Aggregate Bond Index	30
Total		100%

As a secondary measure, asset performance is compared to the returns of a universe of comparable funds, where applicable, over a full market cycle.

During 2001, 2002 and 2003, REMA made cash contributions of $0.7 million, $2.9 million and $3.2 million, respectively, to the pension plans. REMA expects cash contributions to approximate $6.1 million during 2004.

Information for pension plans with an accumulated benefit obligation in excess of plan assets is as follows:

	December 31,	
	2002	2003
	(In thousands)	
Projected benefit obligation	$13,345	$17,652
Accumulated benefit obligation	9,664	13,122
Fair value of plan assets	4,247	8,389

(b) Savings Plan.

REMA has two employee savings plans that are tax-qualified plans under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and include a cash or deferred arrangement under Section 401(k) of the Code for substantially all its employees.

Under the plans, participating employees may contribute a portion of their compensation, pre-tax or after-tax, generally up to a maximum of 16% of compensation. The savings plans' matching contribution and any payroll period discretionary employer contribution will be made in cash; any discretionary annual employer contribution, as applicable, may be made in Reliant Resources' common stock, cash or both.

REMA's savings plans benefit expense was $3.9 million, $3.7 million and $4.6 million in 2001, 2002 and 2003, respectively.

(c) Postretirement Benefits.

REMA provides some postretirement benefits (primarily medical care and life insurance benefits) for its union retired employees, substantially all of whom may become eligible for these benefits when they retire. REMA funds its union postretirement benefits on a pay-as-you-go basis. REMA uses a December 31 measurement date.

REMA's accumulated postretirement benefit obligation and funded status are as follows:

	Year Ended December 31,	
	2002	2003
	(In thousands)	
Change in Benefit Obligation		
Benefit obligation, beginning of period	$ 7,542	$ 28,964
Service cost	2,262	1,418
Interest cost	547	1,955
Plan amendments	9,454	—
Actuarial loss	9,159	7,377
Benefit obligation, end of period	$ 28,964	$ 39,714
Change in Plan Assets		
Fair value of plan assets, beginning of year	$ —	$ —
Employer contributions	—	(17)
Participant contributions	—	17
Fair value of plan assets, end of year	$ —	$ —
Reconciliation of Funded Status		
Funded status	$(28,964)	$(39,714)
Unrecognized prior service costs	9,454	8,509
Unrecognized actuarial loss	11,766	18,239
Net amount recognized at end of year	$ (7,744)	$(12,966)

Amounts recognized in the consolidated balance sheets are as follows:

	December 31,	
	2002	2003
	(In thousands)	
Accrued benefit cost	$(7,744)	$(12,966)

Net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2001	2002	2003
	(In thousands)		
Service cost — benefits earned during the period	$1,411	$2,262	$1,418
Interest cost on projected benefit obligation	234	547	1,955
Net amortization	—	206	1,832
Net postretirement benefit cost	$1,645	$3,015	$5,205

The significant weighted average assumption used to determine the accumulated postretirement benefit obligation includes the following:

	December 31,	
	2002	2003
Discount rate	6.75%	6.25%

The significant weighted average assumption used to determine the net postretirement benefit cost includes the following:

	Year Ended December 31,		
	2001	2002	2003
Discount rate	7.5%	7.25%	6.75%

The following table shows REMA's assumed health care cost trend rates used to measure the expected cost of benefits covered by REMA's postretirement plan:

	Year Ended December 31,		
	2001	2002	2003
Health care cost trend rate assumed for next year	12.0%	11.25%	10.5%
Rate to which the cost trend rate is assumed to gradually decline	5.5%	5.5%	5.5%
Year that the rate reaches the rate to which it is assumed to decline	2011	2011	2011

Assumed health care cost trend rates have an effect on the amounts reported for REMA's health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects as of December 31, 2003:

	One-Percentage Point	
	Increase	Decrease
	(In thousands)	
Effect on service and interest cost	$ 808	$ (684)
Effect on accumulated postretirement benefit obligation	7,650	(6,555)

During 2002, the retiree medical benefits for certain union employees were redesigned to allow for a company-provided subsidy for premium coverage attributable to qualifying employees. This resulted in a $9.5 million increase in the accumulated postretirement benefit obligation during 2002.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 became law. This law introduces a prescription drug benefit, as well as a federal subsidy under certain circumstances to sponsors of retiree health care benefit plans. In January 2004, the FASB issued FASB Staff Position No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." This FASB staff position permits sponsors of postretirement health care plans that provide a prescription drug benefit to make a one time election to defer accounting for the effects of this law until the earlier of: (a) the issuance of authoritative guidance on accounting for the federal subsidy or (b) the occurrence of a significant event that would call for remeasurement of a plan's assets and obligations, such as a plan amendment, settlement or curtailment. REMA has elected to defer accounting for the effects of this law. The measurements of REMA's accumulated postretirement benefit obligation and net periodic postretirement benefit cost do not reflect the effect of this law. When authoritative guidance on accounting for the federal subsidy is issued, REMA will revise its accounting as required.

(d) Postemployment Benefits.

REMA records postemployment benefits based on SFAS No. 112, "Employer's Accounting for Postemployment Benefits," which requires the recognition of a liability for benefits provided to former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily health care and life insurance benefits for participants in the long-term disability plan). Net postemployment benefit costs were insignificant for 2001 and 2002 and $2.0 million for 2003.

(e) Other Employee Matters.

As of December 31, 2003 approximately 70% of REMA's employees are the subject of four collective bargaining arrangements. None of the employees are subject to arrangements that expire prior to December 31, 2004.

(8) Income Taxes

REMA's current and deferred components of income tax (benefit) expense were as follows:

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Current			
Federal	$(16.2)	$ 47.5	$(18.1)
State	(8.3)	4.5	6.3
Total current	(24.5)	52.0	(11.8)
Deferred			
Federal	16.1	(47.4)	12.6
State	3.9	(12.1)	(16.5)
Total deferred	20.0	(59.5)	(3.9)
Income tax benefit	$ (4.5)	$ (7.5)	$(15.7)

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

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Income (loss) before income taxes	$(5.0)	$(15.1)	$(30.9)
Federal statutory rate	35%	35%	35%
Income tax benefit at statutory rate	(1.7)	(5.3)	(10.8)
Net addition in taxes resulting from:			
State income taxes, net of federal income tax benefit	(2.7)	(4.9)	(6.7)
Other, net	(0.1)	2.7	1.8
Income tax benefit	$(4.5)	$ (7.5)	$(15.7)
Effective rate	91.2%	49.9%	50.7%

Following were REMA's tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases:

	As of December 31,	
	2002	2003
	(In millions)	
Deferred tax assets:		
Non-current:		
Employee benefits	$ 4.4	$ 6.0
Environmental reserves	15.0	11.9
Derivative liabilities, net	—	11.5
Operating loss carryforward	—	6.6
Other	1.1	1.6
Total deferred tax assets	20.5	37.6
Deferred tax liabilities:		
Current:		
Derivative assets, net	8.2	0.7
Total current deferred tax liabilities	8.2	0.7
Non-current:		
Derivative assets, net	3.5	—
Depreciation and amortization	52.2	56.1
Other	4.3	—
Total noncurrent deferred tax liabilities	60.0	56.1
Total deferred tax liabilities	68.2	56.8
Accumulated deferred income taxes, net	$(47.7)	$(19.2)

During 2002, Reliant Resources made non-cash equity contributions to REMA related to current federal income taxes payable of $45.2 million. During 2003, REMA made non-cash equity distributions to Reliant Resources related to current federal taxes receivable of $18.1 million (see note 2(h)).

Tax Attribute Carryovers. At December 31, 2003, REMA had approximately $52 million of state net operating loss carryforwards. The state loss carryforwards can be carried forward to offset future income through the year 2023.

(9) Commitments

(a) Lease Commitments.

Sales-leasebacks. In 2000, REMA entered into separate sale-leaseback transactions with each of three owner-lessors' respective 16.45%, 16.67% and 100% interests in the Conemaugh, Keystone and Shawville generating facilities, respectively, acquired in the REMA acquisition during 2000. As lessee, REMA leases an interest in each facility from each owner-lessor under a facility lease agreement. REMA expects to make lease payments through 2029 under these leases, with total cash payments of $1.3 billion remaining as of December 31, 2003. The lease terms expire in 2026 (Shawville facility) and 2034 (Conemaugh and Keystone facilities). The equity interests in all the subsidiaries of REMA are pledged as collateral for REMA's lease obligations and the subsidiaries have guaranteed the lease obligations.

Additionally, REMA is obligated to provide credit support for its lease obligations. See note 6 for discussion. During 2001, 2002 and 2003, REMA made lease payments of $259.3 million, $137.8 million and $76.8 million, respectively, to lessors related to its obligations under the sale-leaseback transactions. Operating lease expense is recorded using the straight-line method over the life of the individual sale-leaseback transactions. Operating lease expense, including the amortization of deferred lease costs (see footnote 2(n)), was $59.6 million, $60.1 million and $59.8 million for the years ended December 31 2001, 2002 and 2003, respectively.

The lease documents contain restrictive covenants that restrict REMA's ability to, among other things, make dividend distributions unless REMA satisfies various conditions. As of December 31, 2003, all of these conditions were met.

The following table sets forth REMA's obligation under these long-term operating leases (in millions):

2004	$ 84.4
2005	74.7
2006	63.7
2007	64.6
2008	62.1
Thereafter	997.2
	$1,346.7

Other Operating Leases. REMA leases some equipment and vehicles under noncancelable operating leases extending through 2005. Future minimum rentals under lease agreements are $92,000 and $74,000 in 2004 and 2005, respectively.

Rent expense incurred under other operating leases aggregated approximately $0.4 million, $0.3 million and $0.1 million for 2001, 2002 and 2003, respectively.

(b) Other Commitments.

Fuel Supply and Commodity Transportation Commitments. REMA is a party to several fuel supply contracts and commodity transportation contracts that have various quantity requirements and durations that are not classified as derivatives assets and liabilities and hence are not included in REMA's consolidated balance sheet as of December 31, 2003. Minimum purchase commitment obligations under these agreements are as follows, as of December 31, 2003:

	Fuel Commitments	Transportation Commitments
	(In millions)	
2004	$ 98.7	$ 5.8
2005	68.1	5.8
2006	52.2	5.6
2007	23.6	4.7
2008	14.4	4.7
2009 and thereafter	138.6	40.1
Total	$395.6	$66.7

As of December 31, 2003, the maximum remaining term under any individual fuel supply contract and transportation contract is 16 years and 20 years, respectively.

(10) Contingencies

(a) Legal and Environmental Matters.

Legal Matters.

Bankruptcy of Enron Corp. and Its Affiliates. In the fourth quarter of 2001, Enron Corp. filed a voluntary petition for bankruptcy. Accordingly, REMA recorded a $68.4 million provision, comprised of provisions against 100% of Enron receivables of $3.7 million and net derivative balances of $64.7 million. Reliant Energy Services entered into contracts with Enron on behalf of REMA under Reliant Energy Services' procurement and marketing agreement (see note 3(a)). In 2002, Reliant Energy Services sued Enron Canada Corp., the only Enron party to Reliant Energy Services' netting agreement which is not in bankruptcy, in the United States District Court for the Southern District of Texas to recover amounts owed to Reliant Energy Services, including by and among the Enron parties. The case is pending. However, in January 2003, Enron sued Reliant Energy Services in the United States Bankruptcy Court for the Southern District of New York claiming $13 million based on the unenforceability of the netting agreement.

The non-trading derivatives with Enron were designated as cash flow hedges (see note 5). The unrealized net gain on these derivative instruments previously reported in other comprehensive income (loss) will remain in accumulated other comprehensive income (loss) and will be reclassified into earnings during the period in which the originally designated forecasted transactions occur. During 2002 and 2003, a $44.0 million gain and a $8.6 million gain, respectively, was reclassified into earnings related to these cash flow hedges. As of December 31, 2002 and 2003, the remaining amount to be reclassified into earnings through 2007 was $18.8 million and $10.2 million, respectively.

Environmental Matters.

REMA Ash Disposal Site Closures and Site Contaminations. REMA is responsible for environmental costs related to (a) the closure of six ash disposal sites and (b) site contamination investigations and remediation requirements of four of its generation facilities. Based on REMA's evaluations with assistance from third-party consultants and engineers, REMA has recorded the estimated aggregate costs associated with these environmental liabilities of $34.7 million and $23.1 million as of December 31, 2002 and 2003 respectively, of which REMA expects to spend $8.4 million over the next five years.

New Source Review Matters. The United States Environmental Protection Agency (EPA) has requested information from six of REMA's coal-fired facilities related to work activities conducted at the sites that may be associated with various permitting requirements of the Clean Air Act. REMA has responded to the EPA's requests for information. In addition to the EPA's requests for information, the New Jersey Department of Environmental Protection (NJDEP) requested from the EPA a copy of all correspondence relating to the EPA's request for information for one of the six facilities, which request the EPA has granted. Furthermore, the New York state attorney general's office and the Pennsylvania Department of Environmental Protection recently requested from the EPA a copy of all such correspondence relating to all six facilities, which the EPA granted.

Other Matters. REMA is involved in other legal proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Although REMA cannot predict the outcome of these proceedings, REMA does not expect these matters to have a material adverse effect on its results of operations, financial condition or cash flows.

(b) Reliant Resources' Debt Covenants.

Both Reliant Resources' March 2003 credit facility and its senior secured notes restrict REMA's ability to take specific actions, subject to numerous exceptions that are designed to allow for the execution of Reliant Resources' and its subsidiaries' business plans in the ordinary course, including the preservation and optimization of existing investments in the retail energy and wholesale energy businesses and the ability to provide credit support for commercial obligations. REMA's failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in Reliant Resources being required to repay its borrowings before their due date.

(11) Consolidation of Pennsylvania Regional Operations Office

On January 28, 2003, Reliant Resources announced a plan to consolidate its Pennsylvania regional operations office into the Pittsburgh area. As part of the consolidation, REMA relocated certain operations, administration and staff support functions from the Johnstown, Pennsylvania office to the Pittsburgh area. REMA plans to sell the Johnstown office. In addition, REMA eliminated certain employee positions and offered severance benefits to qualifying employees. To qualify for severance benefits, employees must remain employed through pre-determined retention dates, which extend through April 2004.

Total severance benefits are estimated at $3.3 million and are being accrued over the retention period. During 2003, REMA recorded severance expense totaling $3.3 million and made severance payments totaling $2.3 million. As of December 31, 2003, REMA's accrued liability for severance benefits totaled $1.0 million. Severance expense is classified in operation and maintenance expense in REMA's consolidated statements of operations.

As a result of the anticipated sale of the office in Johnstown, REMA recorded a $6.5 million write-down of the Johnstown office building to its fair value less cost to sell during 2003. The write-down was recorded to depreciation expense.

(12) Subsequent Events

In January 2004, REMA sold certain power generation site permits and water rights to an affiliate for $19.6 million in cash. The permits and water rights were no longer needed for REMA's business. There was no gain or loss recorded on the sale.

On February 12, 2004, Reliant Resources announced a plan, subject to regulatory approval, to mothball 661 MW of capacity at certain peaking plants and units that serve the PJM Interconnection, LLC and to retire the Wayne peaking unit having a capacity of 66 MW. All of the named plants and units are owned by REMA. REMA tested the Wayne peaking unit for impairment as of December 31, 2003 (see note 2(f)). Based on this test, there was no impairment. In 2004, REMA adjusted the remaining useful life of the Wayne peaking unit and expects to record $12.2 million in depreciation expense during 2004 associated with its early retirement.

* * *

INDEX TO FINANCIAL STATEMENTS

ORION POWER HOLDINGS, INC. AND SUBSIDIARIES

Independent Auditors' Reports F-178

Consolidated Statements of Operations for the Year Ended December 31, 2001, for the periods from January 1, 2002 through February 19, 2002 and February 20, 2002 through December 31, 2002 and for the Year Ended December 31, 2003 . . . . . F-181

Consolidated Balance Sheets as of December 31, 2002 and 2003 . . . . . F-182

Consolidated Statements of Cash Flows for the Year Ended December 31, 2001, for the periods from January 1, 2002 through February 19, 2002 and February 20, 2002 through December 31, 2002 and for the Year Ended December 31, 2003 . . . . . F-183

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Year Ended December 31, 2001, for the periods from January 1, 2002 through February 19, 2002 and February 20, 2002 through December 31, 2002 and for the Year Ended December 31, 2003 . . . . F-184

Notes to Consolidated Financial Statements F-185

Supplementary Data F-227

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Orion Power Holdings, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheet of Orion Power Holdings, Inc. and subsidiaries ("the Company") as of December 31, 2002 and 2003, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for the periods from January 1, 2002 to February 19, 2002 and February 20, 2002 to December 31, 2002 and for the year ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits. The consolidated financial statements and the financial statement schedules of the Company for the year ended December 31, 2001, were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements and stated that such 2001 financial statement schedules, when considered in relation to the 2001 basic consolidated financial statements taken as a whole, presented fairly, in all material respects, the information set forth therein, in their reports dated February 19, 2002 (which report on the consolidated financial statements includes an explanatory paragraph concerning the adoption of a new accounting principle in 2001).

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

In our opinion, the 2002 and 2003 consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2002 and 2003, and the results of its operations and its cash flows for the periods from January 1, 2002 to February 19, 2002 and February 20, 2002 to December 31, 2002 and for the year ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in notes 2 and 5 to the consolidated financial statements, the Company changed its accounting for asset retirement obligations and its presentation of revenues and cost of sales associated with non-trading commodity derivatives activities in 2003 and changed its method of accounting for goodwill and other intangibles in 2002.

As discussed above, the consolidated financial statements of the Company for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Such financial statements and financial statement schedules have been revised to give effect to the following transitional disclosures, expanded disclosures and reclassifications:

- As discussed in note 5, the Company has presented the transitional disclosures for 2001 as required by Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). We audited the adjustments described in note 5 that were applied to revise the 2001 financial statements to include the transitional disclosures required by SFAS No. 142, which was adopted by the Company as of January 1, 2002. Our audit procedures with respect to the disclosure in note 5 with respect to 2001 included (1) comparing the previously reported net income to the previously issued financial statements and the adjustments to reported net income representing amortization expense (including any related tax effects) recognized in those periods related to goodwill and intangible assets no longer being amortized as a result of initially applying SFAS No. 142 (including any related tax effects) to the Company's underlying analysis obtained from management and (2) testing the mathematical accuracy of the reconciliation of adjusted net income to reported net income and the related earnings per share amounts.

- As discussed in note 4, the Company has presented selected financial information and unaudited pro forma information for 2001 as if the acquisition had occurred on January 1, 2001. We audited the expanded disclosures and our procedures included (1) comparing the previously reported revenues and net income to the previously issued financial statements and (2) agreeing the expanded pro forma disclosure amounts to the Company's underlying analysis obtained from management.
- The financial statements have also been revised to give effect to the following reclassifications: (1) in note 2(a), for the 2001 financial statements the Company has presented gains and losses on derivative instruments net in revenues rather than separately and has also presented purchased power separately from fuel expense, (2) for the 2001 cash flow statements, the Company has presented amortization of deferred financing fees separately, (3) in note 2(i), for 2001 the Company presented the capitalized interest for the year rather than the cumulative capitalized interest included in the balance sheet as of December 31, 2001.

  We audited these reclassifications that were applied to revise the 2001 financial statements and financial statement schedules to conform to the presentation of such amounts in the 2003 financial statements and financial statement schedules. Our audit procedures with respect to the 2001 amounts included (1) comparing the previously reported tabular presentation of each amount to a reconciliation schedule prepared by management, (2) testing the mathematical accuracy of the underlying analysis and (3) determining the reclassifications were consistent with the 2003 financial statement presentation.

In our opinion, the transitional disclosures, expanded disclosures and reclassifications to the 2001 financial statements and disclosures and financial statement schedules described above have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 financial statements or financial statement schedules of the Company other than with respect to such transitional disclosures, expanded disclosures and reclassifications and, accordingly, we do not express an opinion or any form of assurance on the 2001 financial statements taken as a whole.

Our audit was conducted for the purpose of forming an opinion on the 2002 and 2003 basic consolidated statements taken as a whole. The 2002 and 2003 financial statement schedules are presented for the purpose of additional analysis and are not a required part of the 2002 and 2003 basic consolidated financial statements. These schedules are the responsibility of the Company's management. Such schedules have been subjected to the auditing procedures applied in our audit of the 2002 and 2003 basic consolidated financial statements and, in our opinion, are fairly stated in all material respects when considered in relation to the 2002 and 2003 basic consolidated financial statements taken as a whole.

DELOITTE & TOUCHE, LLP

Houston, Texas
March 5, 2004

The following is a copy of a report previously issued by Arthur Andersen LLP (Andersen). The report has not been reissued by Andersen.

Report of Independent Public Accountants

To Orion Power Holdings, Inc.:

We have audited the accompanying consolidated balance sheets of Orion Power Holdings, Inc. (a Delaware corporation) and subsidiaries (Orion Power) as of December 31, 2000 and 2001, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of Orion Power's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Orion Power Holdings, Inc. and subsidiaries as of December 31, 2000 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 6 to the financial statements, effective January 1, 2001, Orion Power changed its method of accounting for derivative financial instruments.

/s/ ARTHUR ANDERSEN LLP

Vienna, Virginia
February 19, 2002

ORION POWER HOLDINGS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(Thousands of dollars, except per share amounts)			
Revenues:				
Revenues	$1,190,299	$122,408	$1,001,764	$1,182,273
Revenues — affiliates	—	—	20,279	33,042
Total	1,190,299	122,408	1,022,043	1,215,315
Expenses:				
Fuel	420,176	43,282	235,846	301,429
Fuel — affiliates	—	—	98,902	145,220
Purchased power	50,257	3,232	13,831	20,765
Purchased power — affiliates	—	—	42,743	24,735
Operation and maintenance	129,413	22,419	160,196	220,644
General, administrative and development	58,315	86,188	36,330	103,160
Goodwill impairment	—	—	337,500	585,000
Taxes other than income taxes	57,388	8,576	57,013	72,840
Depreciation and amortization	137,932	25,530	136,605	156,533
Total	853,481	189,227	1,118,966	1,630,326
Operating Income (Loss)	336,818	(66,819)	(96,923)	(415,011)
Other Expense:				
Interest expense	(202,825)	(25,067)	(127,515)	(146,724)
Interest income	21,529	1,101	7,112	5,729
Total other expense	(181,296)	(23,966)	(120,403)	(140,995)
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	155,522	(90,785)	(217,326)	(556,006)
Income Tax Expense (Benefit)	54,919	(38,611)	40,090	1,800
Income (Loss) Before Cumulative Effect of Accounting Change	100,603	(52,174)	(257,416)	(557,806)
Cumulative effect of accounting change, net of tax	—	—	—	2,121
Net Income (Loss)	$ 100,603	$(52,174)	$ (257,416)	$ (555,685)
Earnings per average common share:				
Basic	$ 1.02			
Diluted	$ 0.97			

See Notes to the Consolidated Financial Statements

ORION POWER HOLDINGS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2003
	(Thousands of dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,400	$ 33,441
Restricted cash	199,830	189,440
Accounts receivable, net	112,535	111,795
Receivable from affiliates, net	—	221
State income taxes receivable	47,364	34,850
Inventory	61,152	69,479
Derivative assets	8,762	23,045
Accumulated deferred income taxes	53,095	11,530
Prepaid insurance and property taxes	14,535	11,756
Other current assets	12,496	9,345
Total current assets	517,169	494,902
Property, Plant and Equipment, net	3,784,627	3,729,433
Other Assets:		
Goodwill, net	986,037	395,079
Other intangibles, net	434,899	434,413
Derivative assets	7,286	12,150
Deferred financing costs, net	25,808	17,484
Restricted cash	—	8,656
Other	6,279	5,523
Total other assets	1,460,309	873,305
Total Assets	$5,762,105	$5,097,640
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Current portion of long-term debt and short-term borrowings	$ 454,244	$ 407,690
Accounts payable	44,937	49,373
Derivative liabilities	25,479	19,480
Payable to affiliates, net	7,930	—
Accrued expenses	35,898	29,025
Accrued interest	18,800	19,487
Total current liabilities	587,288	525,055
Other Liabilities:		
Accumulated deferred income taxes	385,628	429,168
Derivative liabilities	27,153	17,293
Contractual obligations	85,715	52,439
Other	80,393	72,519
Total other liabilities	578,889	571,419
Long-term Debt	1,724,095	1,585,689
Commitments and Contingencies		
Stockholder's Equity:		
Common stock; par value $1.00 per share (1,000 shares authorized, issued and outstanding)	1	1
Additional paid-in capital	3,152,701	3,233,308
Retained deficit	(257,416)	(813,101)
Accumulated other comprehensive loss	(23,453)	(4,731)
Stockholder's equity	2,871,833	2,415,477
Total Liabilities and Stockholder's Equity	$5,762,105	$5,097,640

See Notes to the Consolidated Financial Statements

ORION POWER HOLDINGS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(Thousands of dollars)			
Cash Flows from Operating Activities:				
Net income (loss)	$100,603	$(52,174)	$(257,416)	$(555,685)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Cumulative effect of accounting change	—	—	—	(2,121)
Impairment of goodwill	—	—	337,500	585,000
Depreciation and amortization	137,932	25,530	136,605	156,533
Non-cash equity contribution of general and administrative costs from stockholder	—	—	—	69,631
Deferred income taxes	30,986	(4,787)	114,381	85,359
(Gain) loss on derivative financial instruments	(11,919)	12,065	3,699	(3,007)
Deferred compensation	1,596	1,763	—	—
Net amortization of contractual rights and obligations	—	—	(3,537)	(5,449)
Amortization of deferred financing costs	16,497	2,633	1,455	9,671
Amortization of revaluation of swaps and debt	—	—	(30,816)	(26,280)
Tax benefit from exercise of options	927	—	—	—
Interest income on officers' notes receivable	(318)	—	—	—
Federal income tax contribution from Reliant Resources, Inc.	—	—	(72,932)	(24,038)
Changes in assets and liabilities:				
Restricted cash	(53,288)	86,339	50,545	1,734
Accounts receivable, net	20,664	(50,375)	58,082	740
Inventory	(14,088)	(539)	(14,328)	(8,327)
Prepaid insurance and property taxes and other current assets	5,763	(44,279)	(10,931)	2,040
Other assets	5,045	(40,431)	(4,637)	(44,764)
Accounts payable	(35,002)	26,041	(35,993)	4,266
Payable/receivable to affiliates, net	—	—	7,930	(8,137)
Accrued expenses	(29,941)	(10,958)	(6,969)	(5,881)
Income taxes receivable/payable	—	—	(32,364)	(2,571)
Deferred revenue	39	(517)	—	—
Accrued interest	(1,365)	16,738	(15,210)	687
Other long-term liabilities	(2,904)	45,802	(70,672)	(2,546)
Net cash provided by operating activities	171,227	12,851	154,392	226,855
Cash Flows from Investing Activities:				
Capital expenditures	(475,863)	(49,642)	(72,117)	(75,646)
Purchases of property, plant and equipment and related assets in acquisition	(26,336)	—	—	—
Net cash used in investing activities	(502,199)	(49,642)	(72,117)	(75,646)
Cash Flows from Financing Activities:				
Proceeds from debt	448,400	21,000	108,200	40,000
Proceeds from issuance of stock, net	272,603	491	—	—
Payments of debt	(331,964)	(78,758)	(495,940)	(199,579)
Contributions from stockholder	—	—	246,832	35,000
Payments on officers' notes receivable	2,498	3,736	—	—
Payments of financing costs	(12,680)	(100)	(27,264)	(589)
Net cash provided by (used in) financing activities	378,857	(53,631)	(168,172)	(125,168)
Net Change in Cash and Cash Equivalents	47,885	(90,422)	(85,897)	26,041
Cash and Cash Equivalents at Beginning of Period	135,834	183,719	93,297	7,400
Cash and Cash Equivalents at End of Period	$183,719	$ 93,297	$ 7,400	$ 33,441
Supplemental Disclosure of Cash Flow Information:				
Cash payments:				
Interest paid (net of amounts capitalized)	$188,930	$ 5,634	$ 166,454	$ 160,023
Income taxes paid (net of income tax refunds received)	55,632	65	—	(56,949)

See Notes to the Consolidated Financial Statements

ORION POWER HOLDINGS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

	Common Stock		Additional Paid-In Capital	Deferred Compensation	Notes Receivable From Officers	Retain Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Comprehensive Income (Loss)
	Shares	Amount							
				(Thousands of dollars, except share amounts)					
Former Orion									
Balance, December 31, 2000	93,095,926	$ 931	$ 1,230,467	$(3,359)	$(5,916)	$ 32,659	$ —	$ 1,254,782	
Net income						100,603		100,603	$ 100,603
Sale of common stock, net of fees	10,552,983	106	272,497					272,603	
Change in notes receivable from officers					2,180			2,180	
Amortization of deferred compensation				1,596				1,596	
Tax benefit — exercise of stock options			927					927	
Cumulative effect of adoption of SFAS No. 133, net of tax of $26 million							(33,330)	(33,330)	(33,330)
Deferred loss from cash flow hedges, net of tax of $4 million							(6,775)	(6,775)	(6,775)
Reclassification of net deferred gain from cash flow hedges							(10,956)	(10,956)	(10,956)
Comprehensive income									$ 49,542
Balance, December 31, 2001	103,648,909	1,037	1,503,891	(1,763)	(3,736)	133,262	(51,061)	1,581,630	
Net loss						(52,174)		(52,174)	$ (52,174)
Exercise of stock options			491					491	
Change in notes receivable from officers					3,736			3,736	
Amortization of deferred compensation				1,763				1,763	
Deferred loss from cash flow hedges, net of tax of $5 million							(6,055)	(6,055)	(6,055)
Reclassification of net deferred loss from cash flow hedges, net of tax of $3 million							3,711	3,711	3,711
Comprehensive loss									$ (54,518)
Balance, February 19, 2002	103,648,909	1,037	1,504,382	—	—	81,088	(53,405)	1,533,102	
Purchase accounting adjustment	(103,648,909)	(1,037)	(1,504,382)	—	—	(81,088)	53,405	(1,533,102)	
Current Orion									
Purchase allocation	1,000	1	2,963,801	—	—	—	—	2,963,802	
Net loss						(257,416)		(257,416)	$(257,416)
Contributions from stockholder			188,900					188,900	
Net deferred loss from cash flow hedges, net of tax of $24 million							(33,829)	(33,829)	(33,829)
Reclassification of net deferred loss from cash flow hedges, net of tax of $7 million							10,376	10,376	10,376
Comprehensive loss									$(280,869)
Balance, December 31, 2002	1,000	1	3,152,701	—	—	(257,416)	(23,453)	2,871,833	
Net loss						(555,685)		(555,685)	$(555,685)
Net contributions from stockholder			80,607					80,607	
Deferred gain from cash flow hedges, net of tax of $8 million							10,765	10,765	10,765
Reclassification of net deferred loss from cash flow hedges, net of tax of $6 million							7,957	7,957	7,957
Comprehensive loss									$(536,963)
Balance, December 31, 2003	1,000	$ 1	$ 3,233,308	$ —	$ —	$(813,101)	$ (4,731)	$ 2,415,477	

See Notes to the Consolidated Financial Statements

ORION POWER HOLDINGS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

In this report "Orion Power Holdings" refers to Orion Power Holdings, Inc. "Orion Power" refers to Orion Power Holdings, Inc. and its subsidiaries collectively unless the context clearly indicates otherwise. Orion Power Holdings, a Delaware corporation, and subsidiaries own and operate electric generation facilities in New York, Ohio, Pennsylvania and West Virginia with an aggregate generating capacity of 6,690 megawatts, as of December 31, 2003. Orion Power typically sells its wholesale products to electric power retailers, which are the entities that supply power to consumers. Power retailers include independent system operators, regulated utilities, municipalities, energy supply companies, cooperatives and retail "load" or customer aggregators. Orion Power has grown its business by strategically acquiring, developing and modernizing non-nuclear generating facilities located in critical locations in regions across the United States.

On February 19, 2002, Orion Power was acquired by merger (the Merger) by a wholly-owned subsidiary of Reliant Resources, Inc. (Reliant Resources). The transaction resulted in the purchase by Reliant Resources of all of Orion Power Holdings' outstanding shares of common stock for $26.80 per share in cash for an aggregate purchase price of approximately $2.9 billion. Reliant Resources funded the acquisition with a $2.9 billion credit facility and $41 million of cash on hand. As a result of the Merger, Orion Power became a wholly-owned subsidiary of Reliant Resources.

Basis of Presentation

These consolidated financial statements present the results of operations for the year ended December 31, 2001 and for the periods from January 1, 2002 through February 19, 2002 (the date that Reliant Resources acquired Orion Power) and February 20, 2002 through December 31, 2002 and for the year ended December 31, 2003. Within these consolidated financial statements, "Current Orion" and "Former Orion" refer to Orion Power after and before, respectively, the Merger. The results of operations in these consolidated financial statements also include general corporate expenses allocated by Reliant Resources to Orion Power subsequent to the Merger. All of the allocations in the consolidated financial statements are based on assumptions that management believes are reasonable under the circumstances. However, these allocations may not necessarily be indicative of the costs and expenses that would have resulted if Orion Power had operated as a separate entity subsequent to the Merger.

The fair value adjustments related to the Merger, which have been pushed down to Orion Power from Reliant Resources, primarily included adjustments in property, plant and equipment, goodwill, contractual rights and obligations, severance liabilities, debt, unrecognized pension and postretirement benefits liabilities and related deferred taxes. For additional information regarding the Merger, see note 4.

(2) Summary of Significant Accounting Policies

(a) Reclassifications.

Some amounts from the previous years have been reclassified to conform to the 2003 presentation of financial statements. These reclassifications do not affect earnings.

As discussed in note 5, "Goodwill and Intangibles," Orion Power has presented the transitional disclosures for 2001 required by SFAS No. 142. Additionally, as discussed in note 2(f), "Summary of Significant Accounting Policies — Property, Plant and Equipment and Depreciation Expense," and in note 5, "Goodwill and Intangibles," for 2001 Orion Power has reclassified air emissions regulatory allowances and the related accumulated amortization from net property, plant and equipment to net intangibles." For the 2001 financial statements and the 2001 pro forma adjustment discussed in note 4, "Business Acquisitions" Orion Power has presented gains and losses on derivative instruments net in revenues rather than separately. Orion Power has also presented purchased power separately from fuel

expense. For the 2001 cash flow statement, Orion Power has presented amortization of deferred financing fees separately from depreciation and amortization. In note 2(i), for 2001, Orion Power presented capitalized interest for the year rather than the cumulative capitalized interest included in the balance sheet as of December 31, 2001.

(b) Use of Estimates and Market Risk and Uncertainties.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates. Orion Power's critical accounting estimates include: (a) goodwill, (b) property, plant and equipment, (c) depreciation expense, (d) derivative activities, (e) contingencies and (f) deferred tax assets valuation allowance and tax liabilities.

Orion Power is subject to the risk associated with price movements of energy commodities and the credit risk associated with its commercial activities. For additional information regarding these risks, see notes 2(d) and (b). Orion Power is subject to risks relating to the reliability of the systems, procedures and other infrastructure necessary to operate its business. Orion Power is also subject to risks relating to changes in laws and regulations; the outcome of pending lawsuits, governmental proceedings and investigations; the effects of competition; liquidity concerns in its markets; changes in interest rates; the availability of adequate supplies of fuel and transportation; weather conditions; financial market conditions and Orion Power's access to capital; the creditworthiness or financial distress of Orion Power's counterparties; actions by rating agencies with respect to Orion Power or its competitors; political, legal, regulatory and economic conditions and developments; the successful operation of deregulating power markets and other items.

(c) Principles of Consolidation.

Orion Power's accounts and those of Orion Power's wholly-owned and majority-owned subsidiaries are included in the consolidated financial statements. All significant intercompany transactions and balances are eliminated in consolidation.

Each of Orion Power New York, LP (Orion NY), Orion Power New York LP, LLC, Orion Power New York GP, Inc., Astoria Generating Company, L.P. (Astoria), Carr Street Generating Station, LP (Carr Street), Erie Boulevard Hydropower, LP (Erie Boulevard), Orion Power MidWest, LP (Orion MidWest), Orion Power MidWest LP, LLC, Orion Power MidWest GP, Inc., Twelvepole Creek, LLC and Orion Power Capital, LLC (Orion Capital) is a separate legal entity and has its own assets.

In January 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51," (FIN No. 46). The objective of FIN No. 46 is to achieve more consistent application of consolidation policies to variable interest entities and to improve comparability between enterprises engaged in similar activities. FIN No. 46 states that an enterprise must consolidate a variable interest entity if the enterprise has a variable interest that will absorb a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both. FIN No. 46 requires entities to either (a) record the effects prospectively with a cumulative effect adjustment as of the date on which FIN No. 46 is first applied or (b) restate previously issued financial statements for the years with a cumulative effect adjustment as of the beginning of the first year being restated.

Orion Power adopted FIN No. 46 on January 1, 2003. FIN No. 46 did not have any impact on Orion Power's consolidated financial statements.

In December 2003, the FASB released FASB Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51" (FIN No. 46R), which replaces FIN No. 46 and modified certain criteria in determining which entities should be considered as variable interest entities. Orion Power does not believe the application of FIN No. 46R will have a material impact to the consolidated financial statements. The application of FIN No. 46R continues to evolve as the FASB continues to address issues submitted for consideration. Orion Power will continue to assess the application of clarified or revised guidance related to FIN No. 46R.

(d) Revenues and Accounting for Hedging Activities.

Power Generation Revenues. Orion Power records gross revenue for energy sales and services related to the electric power generation facilities under the accrual method and these revenues generally are recognized upon delivery. Electric power and other energy services are sold at market-based prices through existing power exchanges or through third-party contracts. Energy sales and services related to the electric power generation facilities not billed by month-end are accrued based upon estimated energy and services delivered. See below for the discussion of the impact of implementation of Emerging Issues Task Force (EITF) Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" As Defined in EITF Issue No. 02-03" (EITF No. 03-11).

Hedging Activities. Effective January 1, 2001, Orion Power adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133), which establishes accounting and reporting standards for derivative instruments. Adoption of SFAS No. 133 on January 1, 2001 resulted in an after-tax increase in accumulated other comprehensive loss of $33 million.

If certain conditions are met, Orion Power may designate a derivative instrument as hedging (a) the exposure to variability in expected future cash flows (cash flow hedge) or (b) the exposure to changes in the fair value of an asset or liability (fair value hedge). This statement requires that a derivative be recognized at fair value in the balance sheet whether or not it is designated as a hedge. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are designated as normal purchases and sales exceptions and are not reflected in the consolidated balance sheets at fair value. For a derivative that is designated as a cash flow hedge, and depending on its effectiveness, changes in fair value are deferred as a component of accumulated other comprehensive income (loss), net of applicable taxes.

Orion Power designates its derivatives as cash flow hedges only if there is a high correlation between price movements in the derivative and the item designated as being hedged. This correlation is measured both at the inception of the hedge and on an ongoing basis, with an acceptable level of correlation of at least 80% to 125% for hedge designation. The gains and losses related to derivative instruments designated as cash flow hedges are deferred in accumulated other comprehensive income (loss), net of tax, to the extent the contracts are effective as hedges, and then are recognized in the results of operations in the same period as the settlement of the underlying hedged transactions. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive income (loss) is reclassified and included in the consolidated statements of operations (a) prior to October 1, 2003, under the captions (i) fuel expense, in the case of hedging activities related to physical natural gas or coal purchases, (ii) purchased power, in the case of hedging activities related to physical power purchases, (iii) revenues, in the case of hedging activities related to physical power and natural gas sales transactions and financial transactions and (iv) interest expense, in the case of interest rate hedging activities and (b) effective October 1, 2003, under the captions (i) fuel expense, in case of hedging activities related to physical natural gas or coal purchases and physical natural gas sales transactions that

do not physically flow, (ii) purchased power, in the case of hedging activities related to physical power purchases that do physically flow, (iii) revenues, in the case of hedging activities related to financial transactions, physical power sales transactions, physical power purchases that do not physically flow and natural gas sales transactions that do physically flow and (iv) interest expense, in the case of interest rate hedging activities. Prior to October 1, 2003, revenues, fuel expense and purchased power related to sale and purchase contracts designated as hedges were generally recorded on a gross basis in the delivery period.

For a derivative not designated as a hedge, changes in fair value are recorded as unrealized gains or losses in the results of operations. If and when correlation ceases to exist at an acceptable level, hedge accounting ceases and changes in fair value are recognized currently in our results of operations. If it becomes probable that a forecasted transaction will not occur, we immediately recognize the respective deferred gains or losses in our results of operations. The associated hedging instrument is then marked to market through our results of operations for the remainder of the contract term unless a new hedging relationship is redesignated. Prior to October 1, 2003, revenues, fuel expense and purchased power related to sale and purchase contracts designated as hedges were generally recorded on a gross basis in the delivery period. In July 2003, the EITF issued EITF No. 03-11, which stated that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. Orion Power's sales and purchases of fuel and purchased power related to its commodity derivative activities physically deliver and the related settlements are reported on a gross basis in the consolidated statement of operations. Therefore, EITF No. 03-11 resulted in no change in revenues, fuel expense and purchased power for the fourth quarter of 2003 and is believed not to have a significant impact on the presentation of future operations. EITF No. 03-11 has no impact on margins or net income. Comparative financial statements for prior periods have not been reclassified to conform to this presentation, as it is not required. In addition, it is not practicable to determine sales and purchases of fuel and purchased power in 2001, 2002 and the nine months ended September 30, 2003 that would have been shown net if EITF No. 03-11 had been applied to the results of operations historically.

In April 2003, the FASB issued SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 149 clarifies when a contract with an initial net investment meets the characteristics of a derivative and when a derivative contains a financing component. SFAS No. 149 also amends certain existing pronouncements, which will result in more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003 and should be applied prospectively. The implementation of SFAS No. 149 did not have a material impact on the consolidated financial statements.

For additional discussion of derivative and hedging activities, see note 6.

Set-off of Derivative Assets and Liabilities. Where derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts," are met, Orion Power presents its derivative assets and liabilities on a net basis in the consolidated balance sheets. Derivative assets/liabilities and accounts receivable/payable are presented separately in the consolidated balance sheets. The derivative assets/liabilities and accounts receivable/payable are set-off separately in the consolidated balance sheets although in certain cases contracts permit the set-off of derivative assets/liabilities and accounts receivable/payable with a given counterparty.

(e) General, Administrative and Development Expenses.

The general, administrative and development expenses in the consolidated statements of operations include (a) certain employee-related costs, (b) certain contractor costs, (c) bad debt expense,

(d) corporate and administrative services, as provided by affiliates (including management services, financial and accounting, cash management and treasury support, legal, information technology system support, office management and human resources) and (e) certain benefit costs. See note 3 for discussion of related party transactions.

(f) Property, Plant and Equipment and Depreciation Expense.

Property, plant and equipment is stated at cost. Cost of acquired property, plant and equipment includes an allocation of the purchase price based on the asset's fair market value. Orion Power expenses all repair and maintenance costs as incurred, including planned major maintenance. Depreciation is computed using the straight-line method based on estimated useful lives commencing when assets, or major components thereof, are either placed in service or acquired, as appropriate.

Property, plant and equipment includes the following:

	Estimated Useful Lives (Years)	December 31, 2002	December 31, 2003
		(In millions)	
Electric generation facilities	10 - 50	$3,221	$3,345
Land improvements	20 - 50	455	455
Land		121	121
Assets under construction		98	48
Total		3,895	3,969
Accumulated depreciation		(110)	(240)
Property, plant and equipment, net		$3,785	$3,729

Orion Power recorded depreciation expense of $128 million, $25 million, $110 million and $132 million for 2001, for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002, and 2003, respectively.

Orion Power periodically evaluates property, plant and equipment for impairment when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. A resulting impairment loss is highly dependent on the underlying assumptions. There were no impairments recognized for 2001, for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002, and 2003. As of December 31, 2002 and 2003, Orion Power performed impairment analyses of certain property, plant and equipment. In addition, in November 2002 and July 2003, Orion Power performed impairment analyses of all of its property, plant and equipment, as Orion Power believed events had indicated that these assets may not be recoverable. Based on these analyses, no impairments were recorded.

If the wholesale energy market outlook changes negatively, Orion Power could have impairments of property, plant and equipment in future periods. In addition, Orion Power's ongoing evaluation of the wholesale energy business could result in decisions to mothball, retire or dispose of generation assets, any of which could result in impairment charges.

See note 14(c) for discussion of Orion Power's Liberty Electric PA, LLC (Liberty) generating station.

(g) Goodwill and Amortization Expense.

Orion Power records goodwill for the excess of the purchase price over the fair value assigned to the net assets of an acquisition. Through 2001, Orion Power amortized goodwill on a straight-line basis over 30 years. Pursuant to the adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) on January 1, 2002, Orion Power discontinued amortizing goodwill. See note 5 for a discussion regarding the adoption of SFAS No. 142. Goodwill amortization expense for 2001 was $857,000. Amortization expense for other intangibles, excluding contractual rights and obligations, for 2001, for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002, and 2003 was $9 million, $1 million, $27 million and $21 million, respectively. See also note 5.

Orion Power periodically evaluates goodwill and other intangibles when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. Effective January 1, 2002, goodwill and other intangibles are evaluated for impairment in accordance with SFAS No. 142 (see note 5). In 2002 Orion Power recognized an impairment charge of $338 million (pre-tax and after-tax) relating to goodwill. Due to the disposition of one of Reliant Resources' plants, not owned by Orion Power, goodwill was tested for impairment effective July 2003. In connection with this analysis, an impairment of $585 million (pre-tax and after-tax) was recognized. For further discussion of goodwill and other intangible asset impairment analyses in 2002 and 2003, see note 5.

(h) Stock-Based Compensation Plans.

Orion Power applied the intrinsic value method of accounting for employee stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25). Under the intrinsic value method, no compensation expense was recorded when options were issued with an exercise price equal to or greater than the market price of the underlying stock on the date of grant. Orion Power complies with the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) and SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure, an amendment to SFAS No. 123" (SFAS No. 148) and discloses the pro forma effect on net income (loss) and per share amounts as if the fair value method of accounting had been applied to all stock awards. The FASB has announced that it plans to require all companies to expense the fair value of employee stock options in 2005. The FASB is still evaluating "fair value" valuation models and other items. Orion Power no longer has stock-based employee compensation as it is a wholly-owned subsidiary of Reliant Resources.

Orion Power Holdings granted options to acquire shares of its common stock at an exercise price less than the market value of Orion Power Holdings' common stock. As of December 31, 2001, Orion Power recognized deferred compensation of $5 million to be amortized over the three-year vesting period. Orion Power recorded $2 million of compensation expense related to these options for the year ended December 31, 2001.

If compensation costs had been determined as prescribed by SFAS No. 123, the net income (loss) and per share amounts would have approximated the following pro forma results for 2001, which take into account the amortization of stock-based compensation, including stock options, to expense on a straight-line basis over the vesting periods (in thousands, except per share amounts):

Pro forma net income	$86,071
Pro forma net income per common share-basic	0.87
Pro forma net income per common share-assuming dilution	0.83

For further information regarding the Orion Power stock-based compensation plan see note 9.

(i) Capitalization of Interest Expense.

Interest expense is capitalized as a component of major projects under construction and is amortized over the estimated useful lives of the assets. During 2001, for January 1, 2002 through February 19, 2002, and February 20, 2002 through December 31, 2002 and during 2003, Orion Power capitalized interest of $24 million, $2 million, $5 million and $0, respectively.

(j) Income Taxes.

Orion Power uses the asset and liability method of accounting for deferred income taxes and measures deferred income taxes for all significant income tax temporary differences. For additional information regarding income taxes, see note 12.

Prior to February 20, 2002, Orion Power filed a consolidated federal income tax return. Orion Power's pre-acquisition consolidated federal income tax returns have been filed through the tax year ending February 19, 2002.

From February 20, 2002 through September 30, 2002, as a wholly-owned subsidiary of Reliant Resources, Orion Power was included in the consolidated income tax returns of CenterPoint Energy, Inc., formerly the majority owner of Reliant Resources.

As of October 1, 2002, Orion Power is included in the consolidated income tax returns of Reliant Resources and calculates its income tax provision on a separate return basis, whereby Reliant Resources pays all federal income taxes on Orion Power's behalf and is entitled to any related tax savings. The difference between Orion Power's current federal income tax expense or benefit, as calculated on a separate return basis, and related amounts paid or received to/from Reliant Resources, if any, are recorded in Orion Power's financial statements as adjustments to additional paid-in capital on Orion Power's consolidated balance sheet. See note 12 for further discussion.

(k) Cash.

Orion Power records as cash and cash equivalents all highly liquid short-term investments with original maturities or remaining maturities at date of purchase of three months or less.

(l) Restricted Cash.

Restricted cash primarily includes cash at certain subsidiaries, the distribution or transfer of which to Orion Power Holdings or its other subsidiaries, is restricted by financing and other agreements, but is available to the applicable subsidiary to use to satisfy certain of its obligations. For a discussion of Orion Power's various financing agreements, see note 7. The following table details Orion Power's current and long-term restricted cash by reporting entity:

	December 31,	
	2002	2003
	(In millions)	
Orion MidWest	$ 72(1)	$ 64(1)
Orion NY	73(1)	119(1)
Orion Capital	27(1)	—(1)
Liberty Electric PA, LLC	28(1)	15(1)
Total current and long-term restricted cash	$200	$198

(1) The credit facilities and other debt agreements of certain of Orion Power Holdings' subsidiaries contain various covenants that include, among others, restrictions on the payment of dividends to Orion Power Holdings unless certain conditions are satisfied.

(m) Allowance for Doubtful Accounts.

Accounts and notes receivable, principally from customers, in the consolidated balance sheets are net of an allowance for doubtful accounts of $2 million and $7 million at December 31, 2002 and 2003, respectively. The net provision for doubtful accounts in the consolidated statements of operations for February 20, 2002 through December 31, 2002, and 2003 was $1 million and $6 million, respectively.

(n) Inventory.

Inventory consists of materials and supplies, including spare parts, coal and heating oil. All inventory is valued at the lower of average cost or market. Below is a detail of inventory:

	December 31,	
	2002	2003
	(In millions)	
Materials and supplies	$32	$35
Coal	4	20
Heating oil	25	14
Total inventory	$61	$69

(o) Environmental Costs.

Orion Power expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. Amounts that relate to an existing condition caused by past operations and that do not have future economic benefit are expensed. Orion Power records liabilities related to expected future costs related to environmental assessments and/or remediation activities when they are probable and the costs can be reasonably estimated. See note 14(a) for further discussion.

(p) Asset Retirement Obligations.

On January 1, 2003, Orion Power adopted 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. Prior to the adoption of SFAS No. 143, Orion Power recorded asset retirement obligations in connection with the respective business combinations. These obligations were recorded at their present values on the dates of acquisition. Orion Power's asset retirement obligations primarily relate to environmental obligations related to ash site closures at Orion Power's MidWest facilities. The impact of the adoption of SFAS No. 143 resulted in a gain of $2 million, net of tax of $2 million, which is reflected as a cumulative effect of an accounting change in the consolidated statement of operations for 2003.

The impact of the adoption of SFAS No. 143 for Orion Power's operations resulted in a January 1, 2003 cumulative effect of an accounting change to record (a) a $1 million increase in the carrying values of property, plant and equipment, (b) a $44 thousand increase in accumulated depreciation of property, plant and equipment, (c) a $3 million decrease in asset retirement obligations and (d) a $2 million increase in deferred income tax liabilities.

If Orion Power had adopted SFAS No. 143 on January 1, 2001, the impact would have been immaterial to consolidated net income (loss) for 2001, for January 1, 2002 through February 19, 2002 and February 20, 2002 through December 31, 2002.

The following table presents the detail of the asset retirement obligations, which are included in other long-term liabilities in the consolidated balance sheet (in thousands):

Balance at January 1, 2003	$1,951
Accretion expense	116
Additions	60
Balance at December 31, 2003	$2,127

(q) Deferred Financing Costs.

Deferred financing costs are costs incurred in connection with obtaining financings. These costs are deferred and amortized, using the straight-line method, which approximates the effective interest method, over the life of the related debt. From October 29, 2002 through December 31, 2003, Orion Power had incurred approximately $29 million in financing costs related to its 2002 refinancing. Orion Power capitalized $28 million and directly expensed $1 million in fees and other costs related to this refinancing.

During 2001, for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003, Orion Power amortized $16 million, $3 million, $1 million and $10 million of deferred financing costs to interest expense. As of December 31, 2002 and 2003, $26 million and $17 million, respectively, of net deferred financing costs were classified in other long-term assets in the consolidated balance sheets. See note 7 for discussion of Orion Power's various financing agreements.

(r) Customer Concentration.

The following tables represent customers who contributed in excess of 10% of the consolidated revenues for 2001, for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003 (in millions, except percentages):

	Former Orion			
	Year Ended December 31, 2001		January 1, 2002 through February 19, 2002	
Customer	Revenue	Percentage of Total Revenue	Revenue	Percentage of Total Revenue
New York Independent System Operator (NYISO)	$567	48%	$53	43%
Duquesne Light Company	406	34%	53	43%
Niagara Mohawk Corporation (Niagara Mohawk)	—	—	13	11%

	Current Orion			
	February 20, 2002 through December 31, 2002		Year Ended December 31, 2003	
Customer	Revenue	Percentage of Total Revenue	Revenue	Percentage of Total Revenue
NYISO	$447	44%	$557	46%
Duquesne Light Company	363	36%	391	32%
Niagara Mohawk	99	10%	123	10%

The following table represents accounts receivable balances in excess of 10% of the total consolidated accounts receivable balance and the related percentages as of December 31, 2002 and 2003 (in millions, except percentages):

	December 31, 2002		December 31, 2003	
Customer	Accounts Receivable Balance	Percentage of Total Accounts Receivable	Accounts Receivable Balance	Percentage of Total Accounts Receivable
Duquesne Light Company	$62	55%	$54	48%
NYISO	30	27%	36	32%
Niagara Mohawk	—	—	12	11%

(s) Prepaid Insurance and Property Taxes.

Prepaid insurance and property taxes are costs paid in advance (but paid when due in the ordinary course of business) for insurance and property taxes. These costs are deferred and amortized, using the straight-line method, over the service period for which the prepayment pertains.

(t) Guarantees and Indemnifications.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Direct Guarantees of Indebtedness of Others," (FIN No. 45) which increases the disclosure requirements for a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also requires a guarantor to recognize, at the inception of a guarantee issued after December 31, 2002, a liability for the fair value of the obligation undertaken in issuing the guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. Orion Power adopted the reporting requirements of FIN No. 45 on January 1, 2003. The adoption of FIN No. 45 had no impact to Orion Power's historical financial statements, as existing guarantees are not subject to the measurement provisions. The adoption of FIN No. 45 did not have a material impact on the consolidated financial position or results of operations as of and for the year ended December 31, 2003 as the fair value of guarantees issued after December 31, 2002 was nominal on the date on which the guarantee was issued. See note 13(e).

(u) Disclosures about Pensions and Other Postretirement Benefits.

In December 2003, the FASB issued a revision to SFAS No. 132, "Employers' Disclosures About Pensions and Other Postretirement Benefits — An Amendment of FASB Statements No. 87, 88 and 106" (SFAS No. 132 (Revised 2003)). This statement revises employers' disclosures about pension plans and other postretirement benefit plans. This statement retains the disclosure requirements contained in SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132), which it replaces. It requires additional disclosures to those in the original SFAS No. 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. Orion Power adopted these additional disclosures. See note 11.

(v) New Accounting Pronouncements.

As of February 20, 2004, no standard setting body or authoritative body has established new accounting pronouncements or changes to existing accounting pronouncements that would have a material impact to Orion Power's results of operations, financial position or cash flows, for which Orion Power had not already adopted and/or disclosed elsewhere in these notes.

(3) Related Party Transactions

The consolidated financial statements include significant transactions between Orion Power and Reliant Resources and its other subsidiaries. The majority of these transactions involve the purchase or sale of energy, capacity, ancillary services, fuel, emissions allowances or related derivatives or services (including transportation, transmission and storage services) by Reliant Energy Services, Inc. (Reliant Energy Services), a wholly-owned subsidiary of Reliant Resources, from or to Orion Power. The following describes related party agreements and transactions:

Support Services Agreement. On October 28, 2002, Orion Power entered into a services arrangement with Reliant Energy Wholesale Service Company (REWSC), a wholly-owned subsidiary of Reliant Resources. REWSC allocates certain support services costs to Orion Power based on Orion Power's direct labor costs relative to the direct labor costs of other entities to which REWSC provides similar services. Management believes this method of allocation is reasonable. These allocations are not necessarily indicative of what would have been incurred had Orion Power been an unaffiliated entity. Orion MidWest and Orion NY may only pay a fixed amount for certain of these services due to contractual restrictions. The excess of the allocated amount over the fixed amount has been recorded as a non-cash equity contribution to Orion Power from Reliant Resources. REWSC billed Orion MidWest and Orion NY approximately $3 million collectively, which was included in general, administrative and development expense for the period from October 28, 2002 through December 31, 2002. In 2003, the amount of support services costs allocated to Orion Power on this basis by REWSC was $84 million, of which $14 million was billed to Orion Power and $70 million was recorded as a non-cash equity contribution from Reliant Resources.

Services Agreements. On October 28, 2002, Orion Power entered into an agreement with Reliant Energy Services to provide support services to Orion Power Holdings' subsidiaries, Orion MidWest and Orion NY, and their respective subsidiaries. Under the support services agreement, Reliant Energy Services will assist the subsidiaries with the following: the sale and purchase of energy related products; the purchase and sale of electric transmission service; the sale and purchase of fuel related products and the sale of allowances for air emissions credits, in connection with the operation of the Orion MidWest and Orion NY electric generating facilities. In addition, Reliant Energy Services will assist in the administration and management of the energy and fuel related products such as scheduling and dispatch of energy related products and scheduling and nomination of fuel related products. These arrangements are provided for a flat monthly fee payable to Reliant Energy Services, plus out-of-pocket costs and expenses and will continue until 60 days after the final maturity date of the Orion MidWest and Orion NY credit agreements which mature in October 2005. From February 20, 2002 through October 27, 2002, these services were provided under a previous agreement entered into at the time of the Merger. Purchases from Reliant Energy Services, recorded in fuel expense and purchased power expense, were $99 million and $43 million and $145 million and $25 million for February 20, 2002 through December 31, 2002, and 2003, respectively. Sales to Reliant Energy Services, recorded in revenue, were $20 million and $33 million and for February 20, 2002 through December 31, 2002 and 2003, respectively.

Technical Services Arrangement. As of July 1, 2002, REWSC agreed to provide personnel and technical services as required to the operating services subsidiaries of Orion Power Holdings under an informal agreement. These services assure that facilities are properly operated and maintained. Amounts incurred under this agreement for February 20, 2002 through December 31, 2002 and 2003 were approximately $3 million and $6 million, respectively, and were included in operations and maintenance expense.

Liberty Station Agency Letter Agreement. Effective February 19, 2002, Liberty Electric Power, LLC (LEP) entered into an agency agreement with Reliant Energy Services wherein, Reliant Energy Services will act as an agent in certain transactions (purchase of station energy, scheduling and dispatching

services) with PJM Interconnection, LLC (PJM) on behalf of LEP. This agreement provides for reimbursement to Reliant Energy Services of amounts paid to PJM on behalf of LEP. The agreement may be terminated by either party upon 10 days written notice. Amounts incurred under this agreement for February 20, 2002 through December 31, 2002 and 2003 were approximately $0 and $1 million, respectively, and were included in operations and maintenance expense. Although this agreement is still in place, there are no longer transactions entered into under it. Transactions are now conducted under the Liberty energy services agreement and gas purchase agreement, as described below.

Liberty Energy Services Agreement and Gas Purchase Agreement. On August 20, 2003, LEP entered into an agreement with Reliant Energy Services to provide the following services to LEP: dispatching of the Liberty station; coordination with PJM; bidding of all energy related products from the Liberty station into PJM on behalf of LEP; and fuel scheduling, coordination with fuel transporters and management of any balancing agreements. Reliant Energy Services receives a flat monthly fee from LEP for providing these services in the amount of $0.1 million. The agreement had an initial term of 60 days and has been extended on a month-to-month basis. Amounts incurred in 2003 under this agreement were $0.4 million. In addition, on August 20, 2003, LEP and Reliant Energy Services entered into a Base Contract for Sale and Purchase of Natural Gas pursuant to which LEP buys natural gas from Reliant Energy Services. Liberty is required to pre-pay Reliant Energy Services at least monthly for all gas purchases. The contract had an initial term of 60 days and has been extended on a month-to-month basis. Amounts incurred under this agreement in 2003 were $20 million.

Other. From February 20, 2002 through December 31, 2002 and during 2003, Reliant Resources made net equity contributions to Orion Power totaling $189 million and $81 million, respectively. For February 20, 2002 through December 31, 2002, the contributions were primarily to fund the redemption of the convertible senior notes, federal income taxes, working capital and interest on the senior notes, partially offset by a deemed distribution related to current federal income taxes of $73 million (see note 2(j)). For 2003, the net contributions were primarily composed of funding interest on the senior notes and support services allocations from REWSC, partially offset by deemed distributions related to current federal income taxes.

In May 2003 and November 2003, Reliant Resources contributed $15 million and $20 million, respectively, to Orion Power, as a partial funding of the semi-annual interest payment of $24 million on the senior notes due in each of May 2003 and November 2003. While Reliant Resources has no obligation, it intends to contribute any funding shortfall for the semi-annual interest payments due in May 2004 and November 2004 should Orion Power Holdings' funds be insufficient. See note 7.

(4) Business Acquisitions

Acquisition by Reliant Resources.

In February 2002, Reliant Resources acquired all of Orion Power's outstanding shares of common stock for an aggregate purchase price of $2.9 billion. Reliant Resources funded the acquisition with a $2.9 billion credit facility and $41 million of cash on hand.

Reliant Resources accounted for the acquisition as a purchase with assets and liabilities reflected at their estimated fair values. The excess of the purchase price over the fair value of net assets acquired was recorded as goodwill for $1.3 billion. The fair value adjustments have been pushed down to Orion Power from Reliant Resources and primarily included adjustments in property, plant and equipment, goodwill, contractual rights and obligations, severance liabilities, debt, unrecognized pension and postretirement benefits liabilities and related deferred taxes. These fair value adjustments were finalized in February 2003, based on final valuations of property, plant and equipment, intangible assets and other assets and

obligations. There were no additional material modifications to the preliminary adjustments from December 31, 2002.

Reliant Resources' net purchase price allocated to Orion Power's book value was as follows, in millions:

	Purchase Price Allocation
Current assets	$ 636
Property, plant and equipment	3,823
Goodwill	1,324
Other intangibles	477
Other long-term assets	103
Total assets acquired	6,363
Current liabilities	(1,777)
Current contractual obligations	(29)
Long-term contractual obligations	(86)
Long-term debt	(1,006)
Other long-term liabilities	(501)
Total liabilities assumed	(3,399)
Net assets acquired	$ 2,964

Adjustments to property, plant and equipment and other intangibles, excluding contractual rights, are based primarily on valuation reports prepared by independent appraisers and consultants.

The following factors contributed to the recognized goodwill of $1.3 billion: commercialization value attributable to Reliant Resources' trading capabilities, commercialization and synergy value associated with fuel procurement in conjunction with Reliant Resources' existing generating plants in the region, Reliant Resources' entry into the New York power market, general and administrative cost synergies with Reliant Resources' existing PJM power market generating assets, and Reliant Resources' risk diversification value due to increased scale, fuel supply mix and the nature of the acquired assets. Of the resulting goodwill, only $105 million was deductible for United States income tax purposes. See note 5 for a discussion of the subsequent goodwill impairment in 2003.

The components of other intangible assets and the related weighted average amortization period consist of the following, as of the acquisition date:

	Purchase Price Allocation	Weighted Average Amortization Period (Years)
	(In millions)	
Air emission regulatory allowances	$314	38
Contractual rights	106	8
Federal Energy Regulatory Commission (FERC) licenses	57	38
Total	$477	

There was no allocation of purchase price to any intangible assets that are not subject to amortization. See note 5 for further discussion of goodwill and intangible assets.

The following table presents selected financial information and unaudited pro forma information for 2001 and 2002, as if the acquisition had occurred on January 1, 2001 and 2002, as applicable:

	Year Ended December 31, 2001		January 1, 2002 through February 19, 2002	
	As Reported	Pro forma	As Reported	Pro forma
	(In millions)			
Revenues	$1,190	$1,168	$122	$107
Net income (loss)	101	104	(52)	(56)

These unaudited pro forma results, based on assumptions deemed appropriate, have been prepared for informational purposes only and are not necessarily indicative of the amounts that would have resulted if the acquisition by Reliant Resources had occurred on January 1, 2001 and 2002, as applicable. Purchase-related adjustments to the results of operations include the effects on revenues, fuel expense, depreciation and amortization, interest expense, interest income and income taxes. Adjustments that affected revenues and fuel expense were a result of the amortization of contractual rights and obligations relating to the applicable power and fuel contracts that were in existence at January 1, 2001 and 2002, as applicable. Such amortization included in the pro forma results above was based on the value of the contractual rights and obligations at February 19, 2002. The amounts applicable to 2002 were retroactively applied to January 1, 2002 through February 19, 2002 to arrive at the pro forma effect on that period. The unaudited pro forma financial information presented above reflects the acquisition by Reliant Resources in accordance with SFAS No. 141, "Business Combinations" and SFAS No. 142. See notes 2(g) and 5.

Former Orion Acquisition.

The acquisition described below occurred prior to the Merger with Reliant Resources and amounts described may have been adjusted as a result of the Merger discussed above or are no longer applicable.

Competitive Power Ventures — Atlantic.

In October 2001, Orion Power purchased one combined-cycle power project located in Florida from Competitive Power Ventures Holdings, LLC, a subsidiary of Competitive Power Ventures, Inc., for approximately $26 million in cash (Atlantic Project). This was a 250 megawatt development project located near Palm Beach with substantial expansion capability. During 2002, as a result of the acquisition by Reliant Resources, Orion Power decided to cancel the 250 megawatt Atlantic Project because of capital market and economic considerations.

The acquisition was recorded under the purchase method of accounting. The purchase price was allocated to assets acquired and liabilities assumed based on the estimated fair market value at the date of acquisition. The allocation of the purchase price is as follows:

	Purchase Price Allocation
	(In millions)
Current assets	$ 5
Property, plant and equipment	21
Net assets acquired	$26

(5) Goodwill and Intangibles

In July 2001, the FASB issued SFAS No. 142, which states that goodwill and certain intangibles with indefinite lives will not be amortized into results of operations, but instead will be reviewed periodically for impairment and charged to results of operations in periods in which the recorded value of goodwill and

certain intangibles with indefinite lives exceeds their fair values. Orion Power adopted the provisions of the statement, which apply to goodwill and intangible assets acquired prior to June 30, 2001 on January 1, 2002, and thus Orion Power discontinued amortizing goodwill into its results of operations. A reconciliation of 2001 reported net income and earnings per share to the amounts adjusted for the exclusion of goodwill amortization with a comparison to 2002 and 2003 follows:

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(In millions)			
Reported net income (loss)	$ 101	$(52)	$(257)	$(556)
Add: Goodwill amortization, net of tax	1	—	—	—
Adjusted net income (loss)	$ 102	$(52)	$(257)	$(556)
Adjusted basic and diluted earnings per share(1):				
Basic EPS	$1.02			
Diluted EPS	0.97			

(1) Earnings per share were not affected by the exclusion of goodwill amortization due to the immaterial nature of the amount in 2001. As of the Merger date all the shares were purchased by Reliant Resources as such, no earnings per share data is presented subsequent to the Merger date.

Intangibles. Other intangible assets consist of the following:

	Weighted Average Amortization Period (Years)	December 31, 2002		December 31, 2003	
		Carrying Amount	Accumulated Amortization	Carrying Amount	Accumulated Amortization
		(In millions)			
Air emissions regulatory allowances	38	$325	$(26)	$ 375	$ (46)
Contractual rights	8	106	(26)	105	(54)
FERC licenses	38	57	(1)	57	(3)
Total		$488	$(53)	$ 537	$(103)

Orion Power's measurement of the fair value of other intangibles, except contractual rights, was determined by Orion Power with the assistance of an independent third party appraiser based on a weighted average approach considering both an income approach, using future discounted cash flows, and a market approach, using acquisition multiples, including price per megawatt, based on publicly available data for recently completed transactions.

Orion Power recognizes specifically identifiable intangibles, including air emissions regulatory allowances it has been issued or those it is entitled to be allocated during the remaining useful lives of the plants, contractual rights and obligations and FERC licenses for its hydroelectric plants, when specific rights and contracts are acquired. Orion Power amortizes air emissions regulatory allowances on a units-of-production basis as utilized. The amortization of other intangibles, including FERC licenses, but excluding contractual rights, are recorded on a straight-line basis over the lesser of their contractual or estimated useful lives. Orion Power has no intangible assets, other than goodwill, with indefinite lives recorded as of December 31, 2003. Therefore, all intangibles, except goodwill, are subject to amortization.

Estimated amortization expense, excluding contractual rights and obligations (see below), for the next five years is as follows (in millions):

2004	$36
2005	19
2006	15
2007	13
2008	11
Total	$94

In connection with the Merger, Orion Power recorded the fair value of certain fuel and power contracts acquired. Orion Power estimated the fair value of the contracts using forward pricing curves as of the acquisition date over the life of each contract. Those contracts with positive fair value at the date of acquisition (contractual rights) were recorded to intangible assets and those contracts with negative fair values at the date of acquisition (contractual obligations) were recorded to other long-term liabilities in the consolidated balance sheet.

Contractual rights and contractual obligations are amortized to fuel expense and revenues, as applicable, based on the estimated realization of the fair value established on the acquisition date over the contractual lives. There may be times during the life of the contract when accumulated amortization exceeds the carrying value of the recorded assets or liabilities due to the timing of realizing the fair value established on the acquisition date.

Orion Power amortized $26 million and $29 million of contractual rights and contractual obligations, respectively, for a net amount of $3 million, for February 20, 2002 through December 31, 2002. Orion Power amortized $28 million and $33 million of contractual rights and contractual obligations, respectively, for a net amount of $5 million during 2003. Estimated amortization of contractual rights and contractual obligations, excluding Liberty's terminated tolling agreement (see notes 7(a) and 14(c)), for the next five years is as follows:

	Contractual Rights	Contractual Obligations	Net Increase in Income
		(In millions)	
2004	$17	$(31)	$14
2005	—	(9)	9
2006	—	(3)	3
2007	—	(1)	1
2008	—	(1)	1
Total	$17	$(45)	$28

Goodwill. The following table shows the composition of goodwill for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003:

	Former Orion	Current Orion	
	January 1, 2003 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(In millions)	(In millions)	
Beginning balance	$102	$1,324	$ 986
Impairment	—	(338)	(585)
Other(1)	—	—	(6)
Ending balance	$102	$ 986	$ 395

(1) Fair value adjustments related to the Merger were finalized in February 2003. See note 4.

As of December 31, 2002 and 2003, Orion Power had $105 million and $95 million, respectively, of net goodwill recorded in the consolidated balance sheets that is deductible for United States income tax purposes for future periods.

SFAS No. 142 requires goodwill to be tested at least annually and more frequently in certain circumstances. The date of Orion Power's annual impairment test was November 1 for 2002 and 2003. A goodwill impairment test is performed in two steps. The initial step is designed to identify potential goodwill impairment by comparing an estimate of the fair value of the applicable reporting unit to its carrying value, including goodwill. If the carrying value exceeds the fair value, a second step is performed, which compares the implied fair value of the applicable reporting unit's goodwill to the carrying amount of that goodwill, to measure the amount of the goodwill impairment, if any.

2002 Annual Goodwill Impairment Test. Orion Power performed an annual impairment test in 2002 effective November 1, 2002. Based on the fair values determined by management, with the assistance of an independent appraiser, Orion Power recorded an impairment of $338 million in the fourth quarter of 2002. The circumstances leading to the impairment include: a decline in recent acquisition multiples (price per megawatt) for comparable assets sold due to a significant increase in the number of assets held for sale across the market as energy companies attempt to address capital and liquidity concerns; the constrained development of efficient unregulated markets in which we operate due to regulatory, capital and liquidity concerns; weaker prices for electric energy, capacity and ancillary services; and market contraction.

July 2003 Goodwill Impairment Test. On July 9, 2003, Reliant Resources entered into a definitive agreement to sell a power generation plant, Desert Basin. The sale closed in October 2003. Orion Power did not own the plant. As a result of the sale, Reliant Resources was required to allocate a portion of the goodwill in the wholesale energy reporting unit to the Desert Basin plant operations on a relative fair value basis as of July 2003 in order to compute the gain or loss on disposal. Reliant Resources was also required to test the recoverability of goodwill in the remaining wholesale energy reporting unit as of July 2003.

As a result of the July 2003 test, Orion Power recognized an impairment of $585 million (pre-tax and after-tax) in the third quarter of 2003. This impairment was due to a decrease in the estimated fair value of Orion Power. This change in fair value was primarily due to: reduced projected commercialization opportunities related to its power generation assets; lower projected regulatory capacity values due to the lack of development of appropriate market structures and a lower outlook for revenues from existing regulatory capacity markets; reduced long-term margins from its existing portfolio as a result of lowering the estimates of the margins required to induce new capacity to enter the markets; lower market and comparable public company values data; and the level of working capital; partially offset by reductions in

Orion Power's projected commercial, operational and support groups costs and lower projected operations and maintenance expense.

2003 Annual Goodwill Impairment Tests. Orion Power performed its annual goodwill impairment test effective November 1, 2003 and determined that no additional impairments of goodwill had occurred since July 2003.

Estimation of Fair Value. Orion Power estimates reporting unit fair value based on a number of subjective factors, including: (a) appropriate weighting of valuation approaches (income approach, market approach and comparable public company approach), (b) projections about future power generation margins, (c) estimates of future cost structure, (d) discount rates for Orion Power's estimated cash flows, (e) selection of peer group companies for the public company approach, (f) required level of working capital, (g) assumed terminal value and (h) time horizon of cash flow forecasts.

The income approach used in the analyses is a discounted cash flow analysis based on Orion Power's internal forecasts and contains numerous assumptions made by management and the independent appraiser, any of which if changed could significantly affect the outcome of the analyses. Orion Power believes the income approach is the most subjective of the approaches.

Management has determined the fair value of Orion Power, with the assistance of an independent appraiser. In determining the fair value of Orion Power in 2003, the following key assumptions were made: (a) the markets in which Orion Power operates will continue to be deregulated; (b) demand for electricity will grow, which will result in lower reserve margins; (c) there will be a recovery in electricity margins over time to a level sufficient such that companies building new generation facilities can earn a reasonable rate of return on their investment and (d) the economics of future construction of new generation facilities will likely be driven by regulated utilities. As part of this process, all of Orion Power's power generation facilities and those of others in the regions in which Orion Power operates were modeled. The following table summarizes certain of these significant assumptions:

	November 2002	July 2003	November 2003
Number of years used in internal cash flow analysis	15	15	15
EBITDA multiple for terminal values	7.5	7.5	7.5
Risk-adjusted discount rate for estimated cash flows	9.0%	9.0%	9.0%
Average anticipated growth rate for demand in power(1)	2.0%	2.0%	2.0%
After-tax return on investment for new investment(2)	9.0%	7.5%	7.5%

(1) Depending on the region, the specific rate is projected to be somewhat higher or lower.

(2) Based on the assumption in 2003 that regulated utilities will be the primary drivers underlying the construction of new generation facilities, Orion Power has assumed that the after-tax return on investment will yield a return representative of a regulated utility's cost of capital (7.5%) rather than that of an independent power producer (9.0%). Based on changes in assumed market conditions, including regulatory rules, Orion Power has changed the projected time horizon for substantially achieving the after-tax return on investment to 2008-2012 (depending on region). Formerly, Orion Power had assumed that the time horizon for substantially achieving this rate of return was 2006-2010.

Potential Future Impairments of Goodwill. Because Orion Power recognized a goodwill impairment in 2003, in the near future, if actual results of operations are worse than projected or Orion Power's market outlook changes negatively, Orion Power could have additional impairments of goodwill that would need to be recognized. In addition, ongoing evaluations of the wholesale energy business could result in decisions to mothball, retire or dispose of additional generation assets, any of which could result in additional impairment charges related to goodwill, impact Orion Power's fixed assets' depreciable lives or result in fixed asset impairment charges.

(6) Derivative Instruments

Orion Power is exposed to various market risks. These risks arise from the ownership of assets and operation of the business. To the extent permitted by the Orion MidWest and Orion NY credit agreements, Orion Power utilizes derivative instruments such as futures, physical forward contracts and swaps to mitigate the impact of changes in electricity, natural gas and fuel prices on Orion Power's operating results and cash flows. Orion Power utilizes interest rate swaps to mitigate the impact of changes in interest rates and other financial instruments to manage various other market risks.

Reliant Resources has a risk control framework, which Orion Power is subject to, designed to monitor, measure and define appropriate transactions to hedge and manage the risk in its existing portfolio of assets and contracts and to authorize new transactions. These risks fall into three different categories: market risk, credit risk and operational risk. Orion Power believes that it has effective procedures for evaluating and managing these risks to which it is exposed. Key risk control activities include definition of appropriate transactions for hedging, 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, value-at-risk and other risk measurement metrics. Orion Power seeks to monitor and control its risk exposures through a variety of separate but complementary processes and committees, which involve business unit management, senior management and Reliant Resources' board of directors.

Derivatives primarily used by Orion Power are described below:

- Futures contracts are exchange-traded standardized commitments to purchase or sell an energy commodity or financial instrument, or to make a cash settlement, at a specific price and future date.
- Physical forward contracts are commitments to purchase or sell energy commodities in the future.
- Swap agreements require payments to or from counterparties based upon the differential between a fixed price and variable index price (fixed price swap) or two variable index prices (variable price swap) for a predetermined contractual notional amount. The respective index may be an exchange quotation or an industry pricing publication.
- Option contracts convey the right to buy or sell an energy commodity or a financial instrument at a predetermined price or settlement of the differential between a fixed price and a variable index price or two variable index prices.

Derivative assets and liabilities at December 31, 2002 and 2003 are as follows:

	Assets		Liabilities		Net Assets (Liabilities)
	Current	Long-Term	Current	Long-Term	
			(In millions)		
December 31, 2002:					
Derivative activities:					
Cash flow hedges — offset to accumulated other comprehensive income (loss):					
Commodity	$ 4	$ 6	$ (3)	$ —	$ 7
Interest	—	—	(21)	(26)	(47)
Total	4	6	(24)	(26)	(40)
Derivatives marked to market through earnings	5	1	(1)	(1)	4
Total derivative assets and liabilities	$ 9	$ 7	$(25)	$(27)	$(36)
December 31, 2003:					
Derivative activities:					
Cash flow hedges — offset to accumulated other comprehensive income (loss):					
Commodity	$17	$10	$ —	$ —	$ 27
Interest	—	—	(18)	(17)	(35)
Total	17	10	(18)	(17)	(8)
Derivatives marked to market through earnings	6	2	(1)	—	7
Total derivative assets and liabilities	$23	$12	$(19)	$(17)	$ (1)

(a) Derivative Activities.

To reduce the risk from market fluctuations in the results of operations and the resulting cash flows, Orion Power may enter into energy derivatives in order to hedge some expected purchases of electric power, natural gas and other commodities and sales of electric power (energy derivatives) to the extent permitted by the Orion MidWest and Orion NY credit agreements. The energy derivative portfolios are managed to complement the Orion Power asset portfolio, reducing overall risks.

The fair values of Orion Power's derivative activities as of December 31, 2002 and 2003, are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods.

Cash flow hedge ineffectiveness for 2001, for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003 was immaterial. In addition, no component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003.

Below is a reconciliation of Orion Power's net derivative assets (liabilities) to accumulated other comprehensive income (loss), net of tax, as of December 31, 2002 and 2003:

	As of December 31,	
	2002	2003
	(In millions)	
Net derivative liabilities	$(36)	$(1)
Derivatives not designated as cash flow hedges	(4)	(7)
Deferred tax assets attributable to accumulated other comprehensive loss on cash flow hedges	17	3
Accumulated other comprehensive loss from derivative instruments, net of tax(1)	$(23)	$(5)

(1) As of December 31, 2003, Orion Power expects $1 million of accumulated other comprehensive loss to be reclassified into the results of operations during 2004.

As of December 31, 2002 and 2003, the maximum length of time Orion Power is hedging its exposure to the variability in future cash flows for forecasted transactions, excluding the payment of variable interest on existing financial instruments, is three years and two years, respectively. As of December 31, 2002 and 2003, the maximum length of time Orion Power is hedging its exposure to the payment of variable interest rates is seven years and six years, respectively.

For a discussion of Orion Power's interest rate derivative instruments designated as cash flow hedges, see note 7(b).

(b) Credit Risk.

Credit risk is inherent in Orion Power's commercial activities and relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. Reliant Resources has broad credit policies and parameters, to which Orion Power is subject. Orion Power seeks to enter into contracts that permit it to net receivables and payables with a given counterparty. Orion Power also enters into contracts that enable it to obtain collateral from a counterparty as well as to terminate upon occurrence of certain events of default. The credit risk control organization establishes counterparty credit limits. Reliant Resources employs tiered levels of approval authority for counterparty credit limits, with authority increasing from the credit risk control organization through senior management. Credit risk exposure is monitored daily and the financial condition of Orion Power's counterparties is reviewed periodically.

If any of Orion Power's counterparties failed to perform, Orion Power might be forced to acquire alternative hedging arrangements or be required to replace the underlying commitment at then-current market prices. In this event, Orion Power might incur additional losses in addition to amounts owed to us by the counterparty. For information regarding the tolling agreement related to Liberty, see note 14(c).

For counterparties representing greater than 10% of Orion Power's total credit exposure, see note 2(r).

(7) Credit Facilities, Notes and Other Debt

The following table presents the debt outstanding to third parties as of December 31, 2002 and 2003:

	December 31,					
	2002			2003		
	Weighted Average Stated Interest Rate(1)	Long-Term	Current(2)	Weighted Average Stated Interest Rate(1)	Long-Term	Current(2)
	(In millions, except interest rates)					
Banking or Credit Facilities and Notes						
Orion Power Holdings senior notes	12.00%	$ 400	$ —	12.00%	$ 400	$ —
Orion MidWest and Orion NY term loans	3.96	1,211	109	3.93	1,093	125
Orion MidWest revolving working capital facility	3.92	—	51	—	—	—
Orion NY revolving working capital facility	—	—	—	—	—	—
Liberty credit agreement:						
Floating rate debt	3.02	—	103(3)	2.40	—	97(3)
Fixed rate debt	9.02	—	165(3)	9.02	—	165(3)
Other						
Adjustment to fair value of debt(4)	—	66	8	—	58	8
Adjustment to fair value of interest rate swaps(4)	—	46	18	—	34	13
Capital lease	6.20	1	—	6.20	1	—
Total debt		$1,724	$454		$1,586	$408

(1) The weighted average stated interest rate is for borrowings outstanding as of December 31, 2002 or 2003, as applicable.

(2) Includes amounts due within one year of the date noted, as well as loans outstanding under revolving and working capital facilities classified as current liabilities.

(3) The entire balance outstanding under this credit agreement has been classified as current as of December 31, 2002 and 2003. Included in the outstanding amount as of December 31, 2003, is $2 million and $2 million of scheduled principal payments, which were due in October 2003 and January 2004, respectively, for which no payment has been made. As interest payments due in October 2003 and January 2004 were deferred, additional interest will be charged on the past due interest amounts. Of the amount shown as current under the Liberty credit agreement, $11 million matures within 12 months of December 31, 2003. See below and note 14(c) for further discussion.

(4) As a result of the Merger, debt and interest rate swaps were adjusted to fair market value as of the acquisition date. Included in the adjustment to fair value of debt is $74 million and $66 million related to the Orion Power Holdings senior notes as of December 31, 2002 and 2003, respectively. Included in the adjustment to fair value of interest rate swaps is $42 million and $22 million related to the Orion MidWest and Orion NY credit facilities, respectively, as of December 31, 2002. Included in the adjustment to fair value of interest rate swaps is $28 million and $19 million related to the Orion MidWest and Orion NY credit facilities, respectively, as of December 31, 2003. Included in interest expense is amortization of $5 million and $8 million for valuation adjustments for debt and $25 million and $17 million for valuation adjustments for interest rate swaps, respectively, for 2002 and 2003, respectively. These valuation adjustments are being amortized over the respective remaining terms of the related financial instruments.

Restricted Net Assets of Subsidiaries. Certain of Orion Power Holdings' subsidiaries have effective restrictions on their ability to pay dividends or make intercompany loans and advances pursuant to their

financing arrangements. The amount of restricted net assets of Orion Power Holdings' subsidiaries as of December 31, 2003 are approximately $2.7 billion. Such restrictions are on the net assets of Orion Capital, Liberty and LEP. Orion MidWest and Orion NY are indirect wholly-owned subsidiaries of Orion Capital.

Maturities. As of December 31, 2003, maturities of all facilities and other debt were as follows (in millions):

2004	$ 136(1)
2005	1,102(1)
2006	10(1)
2007	10(1)
2008	11(1)
2009 and thereafter	612(1)
Subtotal	1,881
Other items included in debt	113
Total debt	$1,994

(1) Included in the amounts for years 2004, 2005, 2006, 2007, 2008 and 2009 and thereafter are $11 million, $9 million, $10 million, $10 million, $11 million and $211 million, respectively, related to the Liberty credit agreement and which have all been classified as current liabilities in the consolidated balance sheet as of December 31, 2003. See below and note 14(c) for further discussion.

Debt Covenant Compliance. Orion Power was in compliance with all of its debt covenants as of December 31, 2003, other than under the Liberty credit agreement. See below for further discussion.

(a) Banking or Credit Facilities and Notes.

The following table provides a summary of the amounts owed and amounts available as of December 31, 2003 under Orion Power's various committed credit facilities and notes:

	Total Committed Credit	Drawn Amount	Letters of Credit	Unused Amount	Commitments Expiring By December 31, 2004	Principal Amortization and Commitment Expiration Date
	(In millions)					
Orion Power Holdings senior notes	$ 400	$ 400	$—	$—	$ —	May 2010
Orion MidWest and Orion NY term loans	1,218	1,218	—	—	125	March 2004 - October 2005
Orion MidWest revolving working capital facility	75	—	16	59	—	October 2005
Orion NY revolving working capital facility	30	—	7	23	—	October 2005
Liberty credit agreement	284	262	17(1)	5(2)	11	January 2004 - April 2026
Total	$2,007	$1,880	$40	$87	$136	

(1) With consent of the lenders, Liberty has chosen to defer the principal and interest payments due October 2003 rather than draw on the $17 million letter of credit posted as debt service reserve. See below and note 14(c) for further discussion.

(2) As discussed below and in note 14(c), this amount is currently not available to Liberty.

Orion Power Holdings Senior Notes. Orion Power Holdings has outstanding $400 million aggregate principal amount of 12% senior notes. In connection with the Merger, Orion Power Holdings recorded the senior notes at an estimated fair value of $479 million. The $79 million premium is being amortized to

interest expense using the effective interest rate method over the life of the senior notes. The fair value of the senior notes was based on Reliant Resources' incremental borrowing rates for similar types of borrowing arrangements as of the acquisition date. The senior notes are senior unsecured obligations of Orion Power Holdings. Orion Power Holdings is not required to make any mandatory redemption or sinking fund payments with respect to the senior notes. However, if at the time such principal or interest are due, dividends, loans or advances are restricted under the Orion MidWest and Orion NY credit agreements, and funds generated from Orion Power Holdings' other subsidiaries or from other sources are insufficient, payment default under Orion Powers Holdings' senior notes may occur unless Reliant Resources elects to invest additional funds in Orion Power Holdings, which it is not obligated to do. The senior notes are not guaranteed by any of Orion Power Holdings' subsidiaries. The senior notes indenture contains covenants, which bind Orion Power Holdings and certain of its subsidiaries, that include, among others, restrictions on (a) the payment of dividends, (b) the incurrence of indebtedness and the issuance of preferred stock, (c) investments, (d) asset sales, (e) liens, (f) transactions with affiliates, (g) engaging in unrelated businesses and (h) sale and leaseback transactions. See note 3.

Orion MidWest and Orion NY Credit Agreements. During October 2002, the Orion Power Holdings revolving credit facility was prepaid and terminated, and Orion Power refinanced the Orion MidWest and Orion NY credit agreements. In connection with these refinancings, Orion Power applied excess cash of $145 million to prepay and terminate the Orion Power Holdings revolving credit facility and to reduce the term loans and revolving working capital facilities at Orion MidWest and Orion NY. As of the refinancing date, the amended and restated Orion MidWest credit agreement included a term loan of approximately $974 million and a $75 million revolving working capital facility. As of the refinancing date, the amended and restated Orion NY credit agreement included a term loan of approximately $353 million and a $30 million revolving working capital facility. As of December 31, 2002 and 2003, Orion MidWest had $969 million and $884 million, respectively, of term loans outstanding. As of December 31, 2002 and 2003, Orion NY had $351 million and $334 million, respectively, of term loans outstanding. The refinancing included an extension of the maturities of the Orion MidWest and Orion NY credit agreements by three years to October 2005.

The loans under each facility bear interest at LIBOR plus a margin or at a base rate plus a margin. The LIBOR margin is 2.75% as of December 31, 2003 and increases to 3.25% in April 2004 and 3.75% in October 2004. The base rate margin is 1.75% as of December 31, 2003 and increases to 2.25% in April 2004 and 2.75% in October 2004.

The amended and restated Orion MidWest credit agreement is secured by a first lien on substantially all of the assets of Orion MidWest and its subsidiary. Orion NY and its subsidiaries are guarantors of the Orion MidWest obligations under the amended and restated Orion MidWest credit agreement. A substantial portion of the assets of Orion NY and its subsidiaries (excluding certain plants) are pledged, via a second lien, as collateral for this guarantee. The amended and restated Orion NY credit agreement is, in turn, secured by a first lien on a substantial portion of the assets of Orion NY and its subsidiaries (excluding certain plants). Orion MidWest and its subsidiary are guarantors of the Orion NY obligations under the amended and restated Orion NY credit agreement. Substantially all of the assets of Orion MidWest and its subsidiary are pledged, via a second lien, as collateral for this guarantee. Orion MidWest's and Orion NY's obligations under the respective agreements are non-recourse to Orion Power Holdings.

Both the Orion MidWest and Orion NY credit agreements contain affirmative and negative covenants, including negative pledges, that must be met by each borrower under its respective facility to borrow funds or obtain letters of credit, and which require Orion MidWest and Orion NY to maintain a combined debt service coverage ratio of 1.5 to 1.0. These covenants are not anticipated to materially restrict either borrower's ability to borrow funds or obtain letters of credit. The agreements also provide for any available

cash at one borrower to be made available to the other borrower to meet shortfalls in the other borrower's ability to make certain payments, including operating costs. This is effected through distributions of such available cash to Orion Capital, a direct subsidiary of Orion Power Holdings formed in connection with the refinancing. Orion Capital, as indirect owner of each of Orion MidWest and Orion NY, can then contribute such cash to the other borrower. The ability of the borrowers to make dividends, loans or advances to Orion Power Holdings for interest payments or otherwise is restricted. In any event, no distributions may be made after October 28, 2004 until the earlier of maturity or retirement. No distributions are anticipated during the remaining terms of the credit agreements. Any restricted cash, which is not dividended, will be applied on a quarterly basis to prepay outstanding loans at Orion MidWest and Orion NY. See note 2(l) for a detail of restricted cash under the Orion MidWest and Orion NY credit agreements. In addition, the Orion MidWest and Orion NY credit agreements contain operational covenants governing the commercial terms of transactions to purchase or sell fuel and energy related products with Reliant Energy Services and third parties.

Liberty Credit Agreement. In July 2000, LEP and Liberty, indirect wholly-owned subsidiaries of Orion Power Holdings, entered into a credit agreement, that provided for (a) a construction/term loan in an amount of up to $105 million, (b) an institutional term loan in an amount of up to $165 million, (c) a debt service reserve letter of credit facility of $17 million, (d) a revolving working capital facility for an amount of up to $5 million and (e) an equity bridge loan in an amount of up to $41 million. In May 2002, the construction loans were converted to term loans. On the conversion date, Orion Power Holdings made the required cash equity contribution of $30 million into Liberty, which was used to repay a like amount of equity bridge loans advanced by the lenders. A related $41 million letter of credit furnished by Orion Power Holdings as credit support was canceled.

The floating rate loans under the Liberty credit agreement bear interest at LIBOR plus a margin or a base rate plus margin. For the floating rate term loan, as of December 31, 2003, the LIBOR margin is 1.25% and increases to 1.375% in May 2005 and 1.625% in May 2008. As of December 31, 2003, the base rate margin is 0.25% and increased to 0.375% in May 2005 and 0.625% in May 2008. For the revolving working capital facility, as of December 31, 2003, the LIBOR margin is 1.25% and increases to 1.375% in May 2005. As of December 31, 2003, the base rate margin is 0.25% and increases to 0.375% in May 2005.

The lenders under the Liberty credit agreement have a security interest in substantially all of the assets of Liberty and LEP. The outstanding borrowings related to the Liberty credit agreement are non-recourse to Orion Power Holdings and all other subsidiaries. The Liberty credit agreement contains affirmative and negative covenants, including a negative pledge that must be met to borrow funds or obtain letters of credit. Liberty is currently unable to access the revolving working capital facility. Additionally, the Liberty credit agreement restricts Liberty's ability to, among other things, make dividend distributions unless Liberty satisfies various conditions. See note 2(l) for a detail of restricted cash under the Liberty credit agreement.

Given that Liberty is currently in default under the credit agreement, Orion Power has classified the debt as a current liability. Neither Orion Power Holdings nor any other of its subsidiaries is in default under other debt agreements due to the credit agreement default at Liberty. See note 14(c).

(b) Interest Rate Derivative Instruments.

In connection with the Merger, the existing interest rate swaps for the Orion MidWest credit agreement and the Orion NY credit agreement were bifurcated into a debt component and a derivative component. The fair values of the debt components, approximately $59 million for the Orion MidWest credit agreement and $31 million for the Orion NY credit agreement, were based on Reliant Resources' incremental borrowing rates at the acquisition date for similar types of borrowing arrangements. The value

of the debt component is amortized to interest expense as interest rate swap payments are made. See note 6 regarding Orion Power's derivative financial instruments.

Orion Power has entered into a number of interest rate swap contracts having an aggregate notional amount of $250 million as of December 31, 2002 and 2003, that hedge the floating interest rate risk associated with the floating rate long-term debt under the Orion NY credit agreement. As of December 31, 2003, floating rate LIBOR-based interest payments are exchanged for weighted fixed rate interest payments of 7.13% for the Orion NY credit agreement. Orion Power has entered into interest rate swap contracts having an aggregate notional amount of $600 million and $300 million as of December 31, 2002 and 2003, respectively, that hedge the floating interest rate risk associated with the floating rate long-term debt under the Orion MidWest credit agreement. As of December 31, 2003, floating rate LIBOR-based interest payments are exchanged for weighted fixed rate interest payments of 7.66% for the Orion MidWest credit agreement. These swaps qualify as cash flow hedges under SFAS No. 133 and the periodic settlements are recognized as an adjustment to interest expense in the consolidated statements of operations over the term of the swap agreements. See note 6 for further discussion of Orion Power's cash flow hedges.

(8) Stockholders' Equity

The Merger (see note 1) resulted in the purchase by Reliant Resources of all of Orion Power Holdings' outstanding shares of common stock. Subsequently, all of Orion Power Holdings' common stock was beneficially owned by Reliant Resources.

In the Merger, a wholly-owned subsidiary of Reliant Resources (Merger Subsidiary) was merged into Orion Power Holdings. Orion Power Holdings was the surviving entity. In accordance with the Merger, effective on February 19, 2002, Orion Power Holdings converted each issued and outstanding share of common stock, par value $0.01, into the right to receive $26.80 per share in cash resulting in the cancellation of all issued and outstanding shares, warrants and options of Orion Power Holdings. Additionally, each share of common stock of Merger Subsidiary, par value $1.00 per share, issued and outstanding immediately prior to February 19, 2002 was converted into one share of common stock of Orion Power Holdings. As of December 31, 2002 and 2003, Orion Power had 1,000 shares authorized, issued and outstanding with a par value of $1.00 per share.

The following describes Orion Power's equity transactions prior to the Merger:

The Second Amended and Restated Stockholder's Agreement (the Agreement) dated November 5, 1999 stated that at the time of a capital call, Orion Power Holdings would issue warrants to GS Capital Partners II, L.P. (GSCP) and Constellation Power Source, Inc. (CPS) for shares of Orion Power Holdings common stock in accordance with certain formulas, as defined in the Agreement. Under the terms of the original stockholder's agreement between CPS and GSCP, only GSCP was entitled to receive warrants. The warrants had an exercise price equal to the subscription price of the common stock ($10.00 or $15.50) and expire on the tenth anniversary of their issuance. The warrant holder may exercise the warrants for an equivalent number of shares of Orion Power Holdings common stock when accompanied by payment of the full exercise price. The warrant holder may also exercise the warrant without payment and would be entitled to a number of shares of Orion Power Holdings common stock equivalent to (a) the difference between the aggregate Current Market Price, as defined, less the aggregate exercise price, divided by (b) the Current Market Price of one share of common stock. As of December 31, 2001, 705,900 warrants had been issued to Constellation Holdings, Inc. No warrants had been exercised as of December 31, 2001. No more capital is subject to call under this agreement and no more warrants are issuable subsequent to the Merger.

On June 6, 2001, Orion Power Holdings completed a $356 million common stock offering, comprised of 10,400,000 shares sold by Orion Power Holdings and 2,600,000 shares sold by certain selling stockholders at a gross per share offering price of $27.35, resulting in net proceeds of approximately $273 million. Concurrent with this offering, Orion Power Holdings completed a $200 million offering of 4.50% convertible senior notes.

(9) Stock Option Plan

In May 1998, Orion Power Holdings adopted the 1998 Stock Incentive Plan (the plan), which provided for granting of stock options and other equity based awards to directors, officers, employees and consultants. The plan, as amended, provided that up to 7,500,000 shares of common stock may be issued pursuant to such options and other awards. Stock options were granted at an exercise price as determined by the board of directors or a committee designated by the board of directors, were exercisable in installments beginning one year from the date of grant and expired 10 years after the date of grant. The plan permitted the issuance of either incentive stock options or non-qualified stock options. The Merger resulted in the cancellation of all of the outstanding shares, warrants and options of Orion Power Holdings, and as such, the plan was canceled.

Orion Power Holdings granted options to acquire shares of its common stock at an exercise price less than the fair value of its common stock. As of December 31, 2001, Orion Power Holdings recognized deferred compensation of $5 million to be amortized over the three-year vesting period. Compensation expense related to these options of $2 million was recorded for 2001.

The following summarizes options granted to directors, officer and employees:

	Number of Shares	Weighted Average Exercise Price
Outstanding at December 31, 2000	5,237,379	$ 15.23
Granted	468,000	24.10
Forfeited	(37,128)	(20.72)
Exercised	(165,906)	(10.67)
Outstanding at December 31, 2001	5,502,345	16.17
Options exercisable at December 31, 2001	1,871,744	13.08

Exercise prices for options outstanding as of December 31, 2001, ranged from $10 to $29.80. The following table provides certain information with respect to stock options outstanding at December 31, 2001:

Range of Exercise Prices	Stock Options Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
$10.00 - $15.50	2,833,345	$12.03	8.47
$15.51 - $20.00	2,308,000	19.84	8.92
$20.01 - $29.80	361,000	25.24	9.44
	5,502,345	16.17	8.72

The following table provides certain information with respect to stock options exercisable at December 31, 2001:

Range of Exercise Prices	Stock Options Exercisable	Weighted Average Exercise Price
$10.00 - $15.50	1,492,415	$11.31
$15.51 - $20.00	375,478	20.00
$20.01 - $29.80	3,851	26.53
	1,871,744	13.08

The weighted average fair value at date of grant for options granted during 2000 and 2001 were $15.60 and $9.64, respectively, and was estimated using the Black-Scholes option valuation model with the following weighted average assumptions:

	Year Ended December 31, 2000	Year Ended December 31, 2001
Expected life in years	10	10
Risk-free interest rate	5.11%	5.03%
Volatility	35.00%	9.80%
Dividend yield	—	—

(10) Earnings Per Share

The following table presents the basic and diluted earnings per share (EPS) calculation for 2001. As of December 31, 2002 and 2003, all of Orion Power Holdings' common stock was beneficially owned by Reliant Resources and therefore, EPS data is not presented for 2002 or 2003 (in thousands, except per share amounts):

Net income — for basic EPS	$100,603
Effect of dilutive securities:	
Convertible securities	3,414
Net Income — for diluted EPS	$104,017
Diluted Weighted Average Shares Calculation:	
Weighted average shares outstanding	99,071
Plus: Incremental shares from assumed conversions:	
Stock options	1,163
Warrants	3,936
Convertible securities	3,414
Weighted average shares assuming dilution	107,584
Basic EPS	$ 1.02
Diluted EPS	0.97

(11) Retirement and Other Benefit Plans

(a) Pension.

Orion Power sponsors multiple noncontributory defined benefit pension plans covering certain union and non-union employees. Depending on the plan, the benefit payment is either based on years of service

with final average salary and covered compensation, or in the form of a cash balance account which grows based on a percentage of annual compensation and accrued interest.

Orion Power's funding policy is to review amounts annually in accordance with applicable regulations in order to determine contributions necessary to achieve adequate funding of projected benefit obligations. Orion Power uses a December 31 measurement date for its plans. The pension obligation and funded status are as follows:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 39.1	$ 57.6
Service cost	3.4	4.1
Interest cost	2.8	3.9
Settlement loss	—	0.8
Benefits paid	(1.1)	(2.9)
Plan amendments	2.0	0.7
Actuarial loss	11.4	6.6
Benefit obligation, end of year	$ 57.6	$ 70.8
Change in Plan Assets		
Fair value of plan assets, beginning of year	$ 19.8	$ 23.8
Employer contributions	6.0	9.1
Benefits paid	(1.1)	(2.9)
Actual investment return	(0.9)	5.7
Fair value of plan assets, end of year	$ 23.8	$ 35.7
Reconciliation of Funded Status		
Funded status	$(33.8)	$(35.1)
Unrecognized prior service cost	2.0	2.4
Unrecognized actuarial loss	14.3	16.9
Net amount recognized, end of year	$(17.5)	$(15.8)

Amounts recognized in the consolidated balance sheets are as follows:

	December 31,	
	2002	2003
	(In millions)	
Accrued benefit cost	$(18.8)	$(16.3)
Intangible assets	1.3	0.5
Net amount recognized	$(17.5)	$(15.8)

The accumulated benefit obligation for all defined benefit plans was $39 million and $46 million at December 31, 2002 and 2003, respectively.

Net pension cost includes the following components:

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(In millions)		(In millions)	
Service cost — benefits earned during the period	$ 3.0	$0.4	$ 3.0	$ 4.1
Interest cost on projected benefit obligation	2.3	0.3	2.5	3.9
Expected return on plan assets	(1.1)	—	(1.9)	(2.2)
Accounting settlement charge	—	—	—	0.6
Net amortization	0.2	0.2	—	1.0
Net pension cost	$ 4.4	$0.9	$ 3.6	$ 7.4

The significant weighted average assumptions used to determine the pension benefit obligation include the following:

	December 31,	
	2002	2003
Discount rate	6.75%	6.25%
Rate of increase in compensation levels	4.50%	4.50%

The significant weighted average assumptions used to determine the net pension cost include the following:

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
Discount rate	7.75%	7.25%	7.25%	6.75%
Rate of increase in compensation levels	4.00%	4.00%	4.50%	4.50%
Expected long-term rate of return on assets	8.50%	8.50%	8.50%	8.50%

As of December 31, 2003, Orion Power's expected long-term rate of return on pension plan assets is developed based on third party models. These models consider expected inflation, current dividend yields, expected corporate earnings growth and risk premiums based on the expected volatility of each asset category. The expected long-term rates of return for each asset category are weighted to determine the overall expected long-term rate of return on pension plan assets. In addition, peer data and historical returns are reviewed.

Orion Power's pension plan weighted average asset allocations at December 31, 2002 and 2003 and target allocation for 2004 by asset category are as follows:

	Percentage of Plan Assets at December 31,		Target Allocation
	2002	2003	2004
Domestic equity securities	55%	55%	55%
International equity securities	15	15	15
Debt securities	30	30	30
Total	100%	100%	100%

In managing the investments associated with the pension plans, Orion Power's objective is to exceed, on a net-of-fee basis, the rate of return of a performance benchmark composed of the following indices:

Asset Class	Index	Weight
Domestic equity securities	Wilshire 5000 Index	55%
International equity securities	MSCI All Country World Ex-U.S. Index	15
Debt securities	Lehman Brothers Aggregate Bond Index	30
Total		100%

As a secondary measure, asset performance is compared to the returns of a universe of comparable funds, where applicable, over a full market cycle.

During 2001, January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003, Orion Power made cash contributions of $8 million, $1 million, $5 million and $9 million, respectively, to the pension plans. Orion Power expects cash contributions to approximate $9 million during 2004.

Information for pension plans with an accumulated benefit obligation in excess of plan assets is as follows:

	December 31,	
	2002	2003
	(In millions)	
Projected benefit obligation	$57.6	$70.8
Accumulated benefit obligation	38.9	45.8
Fair value of plan assets	23.8	35.7

Two of Orion Power's pension plans were amended on October 15, 2002. A third plan contained the following features: subsidized optional forms of benefits, an early retirement subsidy and a provision for a cost of living adjustment increase, while the other plans did not include these features. The two plans were amended to include these additional features. This resulted in a $2 million increase in the projected benefit obligation in 2002. One of Orion's pension plans was amended on July 23, 2003 to provide certain plan design changes in accordance with a collective bargaining agreement, and was amended again on October 9, 2003 to make certain design changes to the forms of pension distributions under the plan. This resulted in a $0.7 million increase in the projected benefit obligation in 2003.

(b) Savings Plan.

Orion Power has an employee savings plan that is a tax-qualified plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and includes a cash or deferred arrangement under Section 401(k) of the Code for all Orion Power employees.

Under the plan, participating employees may contribute a portion of their compensation, pre-tax or after-tax, generally up to a maximum of 18% of compensation. Orion Power's savings plan matching contribution, any payroll period discretionary employer contribution and any discretionary annual employer contribution will be made in cash.

Orion Power's savings plan benefit expense was $8.1 million, $0.4 million, $1.6 million and $1.5 million in 2001 and for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003, respectively.

(c) Postretirement Benefits.

Orion Power funds the postretirement benefits on a pay-as-you-go basis. Orion Power uses a December 31 measurement date for its plans.

Accumulated postretirement benefit obligation and funded status are as follows:

	Year Ended December 31,	
	2002	2003
	(In millions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 21.8	$ 27.9
Service cost	1.7	1.5
Interest cost	2.2	1.9
Benefit payments	—	(0.6)
Actuarial loss	2.2	0.3
Benefit obligation, end of year	$ 27.9	$ 31.0
Change in Plan Assets		
Fair value of plan assets, beginning of year	$ —	$ —
Employer contributions	—	0.5
Benefits paid	—	(0.5)
Fair value of plan assets, end of year	$ —	$ —
Reconciliation of Funded Status		
Funded status	$(27.9)	$(31.0)
Unrecognized actuarial gain	(6.6)	(5.9)
Net amount recognized, end of year	$(34.5)	$(36.9)

Amounts recognized in the consolidated balance sheets are as follows:

	December 31,	
	2002	2003
	(In millions)	
Accrued benefit cost	$(34.5)	$(36.9)

Net postretirement benefit cost includes the following components:

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(In millions)		(In millions)	
Service cost — benefits earned during the period	$1.3	$0.2	$1.5	$ 1.5
Interest cost on projected benefit obligation	1.4	0.2	2.0	1.9
Net amortization	—	—	—	(0.4)
Net periodic benefit cost	$2.7	$0.4	$3.5	$ 3.0

The significant weighted average assumptions used to determine the accumulated postretirement benefit obligation include the following:

	December 31,	
	2002	2003
Discount rate	6.75%	6.25%
Rate of increase in compensation levels	4.50%	4.50%

The significant weighted average assumptions used to determine the accumulated postretirement benefit cost include the following:

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
Discount rate	7.75%	7.25%	7.25%	6.75%
Rate of increase in compensation levels	4.00%	4.00%	4.50%	4.50%

The following table shows Orion Power's assumed health care cost trend rates used to measure the expected cost of benefits covered by its postretirement plan:

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
Health care cost trend rate assumed for next year	8.0%	12.0%	11.25%	10.5%
Rate to which the cost trend rate is assumed to gradually decline	5.0%	5.5%	5.5%	5.5%
Year that the rate reaches the rate to which it is assumed to decline	2008	2011	2011	2011

Assumed health care cost trend rates have a significant effect on the amounts reported for Orion Power's health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects as of December 31, 2003:

	One-Percentage Point	
	Increase	Decrease
	(In thousands)	
Effect on service and interest cost	$ 610	$ (498)
Effect on accumulated postretirement benefit obligation	5,393	(4,495)

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 became law. This law introduces a prescription drug benefit, as well as a federal subsidy under certain circumstances to sponsors of retiree health care benefit plans. In January 2004, the FASB issued FASB Staff Position No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." This FASB staff position permits sponsors of postretirement health care plans that provide a prescription drug benefit to make a one time election to defer accounting for the effects of this law until the earlier of: (a) the issuance of authoritative guidance on accounting for the federal subsidy or (b) the occurrence of a significant event that would call for remeasurement of a plan's assets and obligations, such as a plan amendment, settlement or curtailment. Orion Power has elected to defer accounting for the effects of this law. The measurements of Orion Power's accumulated postretirement benefit obligation and net periodic postretirement benefit cost do not reflect the effect of this law. When authoritative guidance on accounting for the federal subsidy is issued, Orion Power will revise its accounting as required.

(d) Postemployment Benefits.

Orion Power records postemployment benefits based on SFAS No. 112, "Employer's Accounting for Postemployment Benefits," which requires the recognition of a liability for benefits provided to former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily health care and life insurance benefits for participants in the long-term disability plan). Net postemployment benefit costs were insignificant for 2001 and 2002 and $1 million for 2003.

(e) Other Employee Matters.

As of December 31, 2003, approximately 68% of Orion Power's employees are subject to collective bargaining agreements. The agreements covering 62% of those employees will expire prior to December 31, 2004.

(12) Income Taxes

Orion Power's current and deferred components of income tax expense (benefit) were as follows:

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(In millions)		(In millions)	
Current:				
Federal	$27.3	$(24.6)	$(67.0)	$(69.1)
State	(3.4)	(9.2)	(7.3)	(14.5)
Total current	23.9	(33.8)	(74.3)	(83.6)
Deferred:				
Federal	27.1	(3.5)	109.8	84.7
State	3.9	(1.3)	4.6	0.7
Total deferred	31.0	(4.8)	114.4	85.4
Income tax expense (benefit)	$54.9	$(38.6)	$ 40.1	$ 1.8

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

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(In millions)		(In millions)	
Income (loss) before income taxes and cumulative effect of accounting change	$155.5	$(90.8)	$(217.3)	$(556.0)
Federal statutory rate	35%	35%	35%	35%
Income tax expense (benefit) at statutory rates	54.4	(31.8)	(76.1)	(194.6)
Net addition (reduction) in taxes resulting from:				
Non-deductible goodwill impairment	—	—	118.1	204.8
State income taxes, net of federal income tax benefit	10.8	(6.8)	8.3	2.9
State tax credits	(10.4)	—	(10.2)	(11.8)
Other	0.1	—	—	0.5
Total	0.5	(6.8)	116.2	196.4
Income tax expense (benefit)	$ 54.9	$(38.6)	$ 40.1	$ 1.8
Effective tax rate	35.3%	42.5%	NM(1)	NM(1)

(1) Not meaningful as for February 20, 2002 through December 31, 2002 and 2003, Orion Power had a pre-tax loss of $217 million and $556 million, respectively, and income tax expense of $40 million and $2 million, respectively. The primary reason is due to Orion Power's goodwill impairments for February 20, 2002 through December 31, 2002 and 2003 of $338 million and $585 million, respectively, for which no tax benefit can be recognized, as the goodwill is non-deductible.

Following were Orion Power's tax effects of temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their respective tax bases:

	December 31,			
	2002		2003	
	Current	Long-Term	Current	Long-Term
	(In millions)			
Deferred tax assets:				
Allowance for doubtful accounts	$ 0.4	$ —	$ 3.0	$ —
Inventory writedown	3.8	—	3.8	—
Net operating loss and credit carryforwards	18.2	35.8	—	48.2
Valuation allowances	—	(29.7)	—	(33.6)
Employee benefits	—	18.6	—	24.4
Derivative liabilities	8.0	8.7	—	2.1
Contractual rights and obligations	13.7	—	—	—
Environmental liability	—	6.5	—	3.2
Adjustment to fair value of debt	10.9	46.5	8.6	38.2
Other	1.2	—	0.1	4.0
Total deferred tax assets	56.2	86.4	15.5	86.5
Deferred tax liabilities:				
Prepaid insurance	(2.1)	—	(1.9)	—
Depreciation and amortization	—	(456.0)	—	(511.1)
Derivative assets	(1.0)	(0.4)	(1.5)	—
Contractual rights and obligations	—	(11.4)	—	(0.3)
Other	—	(4.2)	(0.6)	(4.3)
Total deferred liabilities	(3.1)	(472.0)	(4.0)	(515.7)
Net accumulated deferred income tax assets (liabilities)	$53.1	$(385.6)	$11.5	$(429.2)

Tax Attribute Carryovers. As of December 31, 2003, Orion Power had state net operating loss carryovers of $467 million, which are due to expire in tax years 2015 through 2023.

During 2002, a valuation allowance of $30 million was established as part of purchase accounting (see note 4). This valuation allowance resulted from Orion Power's assessment of its future ability to use state net operating losses. During 2003, Orion Power increased its valuation allowance to $34 million, which results primarily from the assessment of Orion Power's future ability to use state net operating losses.

(13) Commitments

(a) Lease Commitments.

Orion Power has entered into various non-cancelable operating lease arrangements for office space, storage space, office furniture and vehicles. These leases terminate at various dates through 2022.

Future minimum payments due under these leases are as follows (in thousands):

	Capital Leases	Operating Leases
2004	$ 126	$ 4,063
2005	126	3,870
2006	126	3,058
2007	126	2,841
2008	126	1,026
2009 and Thereafter	767	4,317
Subtotal	1,397	$19,175
Interest	(388)	
Total	$1,009	

In November 1999, Erie Boulevard entered into a capital lease arrangement for the land at the Watertown hydroelectric plant located in Potsdam, New York. This land houses a maintenance facility and a regional headquarters for the hydroelectric assets. The lease began at the completion of the facility, in October 2000, and expires in 2015. Under the terms of the lease, the monthly payments are $10,500. Erie Boulevard has the option to purchase the land for $450,000 at the end of the lease term.

Total rental expense for 2001, for January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003, was $1.8 million, $0.2 million, $1.6 million and $2.0 million, respectively.

(b) Fuel Contracts and Transportation Commitments.

Orion Power is a party to fuel supply contracts and commodity transportation contracts, that have various quantity requirements and durations that are not classified as derivative assets and liabilities and hence are not included in the consolidated balance sheet as of December 31, 2003. Minimum purchase commitment obligations under these agreements are as follows, as of December 31, 2003:

	Fuel Commitments	Transportation Commitments
	(In millions)	
2004	$152	$ 8
2005	124	9
2006	77	9
2007	30	9
2008	—	9
2009 and thereafter	—	47
Total	$383	$91

As of December 31, 2003 the maximum remaining terms under any individual fuel supply contract and transportation contract is four years and 10 years, respectively.

(c) Provider of Last Resort Contracts.

One of Orion Power Holdings' subsidiaries is contractually obligated through the end of 2004 to provide energy to Duquesne Light Company to satisfy the demands of any customer in its service area that purchases power from Duquesne Light Company as its "provider of last resort." These contracts do not

specify a minimum or maximum quantity of energy to be supplied. Although Orion Power expects to produce more energy than needed to meet these contractual obligations, it is possible that, due to seasonal variations in demand or operational outages, its subsidiary may occasionally need to purchase energy from third parties to cover its contractual obligations. Since these events are likely to occur at times of higher market prices, Orion Power is at risk that the cost of power purchased may exceed the fixed prices for power under contracts with Duquesne Light Company. Failure to provide sufficient energy under the terms of the contracts could give rise to, in addition to other direct damages, penalties of up to $1,000 per megawatt hour, depending upon the circumstances of such under delivery. During the period February 20, 2002 through December 31, 2002 and 2003, Orion Power did not incur or pay any penalties.

(d) Collateral Posting Provided by Reliant Resources.

As a result of credit rating downgrades in the first quarter of 2003, collateral requirements, which are based on a contractual provision relating to creditworthiness and market exposure, were triggered pursuant to a provision in a power contract between Orion MidWest and one of its customers, which required Orion Power to provide collateral of approximately $16 million. On July 30, 2003, this collateral was posted by Reliant Resources on Orion MidWest's behalf. There is no obligation by Orion MidWest to repay this collateral to Reliant Resources. As of December 31, 2003, there have been no changes to the collateral posted by Reliant Resources on Orion MidWest's behalf.

(e) Guarantee.

Together with certain of Reliant Resources' other subsidiaries, Orion Power Holdings is a guarantor of the obligations under Reliant Resources' Amended and Restated Credit and Guaranty Agreement dated as of March 28, 2003, subject to certain limitations under Orion Power Holdings' senior notes. These limitations limit the amount of the guarantee based on a fixed charge coverage ratio, consolidated tangible assets and a restricted payment ceiling test, under the Orion Power Holdings senior notes. Additionally, Orion Power Holdings is the only limited guarantor of the obligations under Reliant Resources' senior secured notes issued in July 2003, subject to the same limitations. None of Orion Power Holdings' subsidiaries guarantee Reliant Resources' senior secured notes.

Reliant Resources has calculated the aggregate amount permitted to be guaranteed under both the guarantee for its March 2003 credit facility and the guarantee for its senior secured notes to be approximately $1.1 billion, which is the maximum potential amount of future payments. These guarantees mature at varying dates from 2007 to 2013.

Both Reliant Resources' March 2003 credit facility and its senior secured notes restrict Orion Power Holdings and its subsidiaries ability to take specific actions, subject to numerous exceptions that are designed to allow for the execution of Reliant Resources' and its subsidiaries' business plans in the ordinary course, including the preservation and optimization of existing investments in the retail energy and wholesale energy businesses and the ability to provide credit support for commercial obligations. Orion Power's failure to comply with these restrictions could result in an event of default under the Reliant Resources' March 2003 credit facility or its senior secured notes that, if not cured or waived, could result in Reliant Resources being required to repay its borrowings before their due date.

(14) Contingencies

(a) Legal and Environmental Matters.

Orion Power is liable under the terms of a consent order issued in 2000 with the New York State Department of Environmental Conservation (NYSDEC) for past releases of petroleum and other substances at two of its generation facilities. Based on Orion Power's evaluations with assistance from

third-party consultants and engineers, Orion Power has developed remediation plans for both facilities. As of December 31, 2002 and 2003, Orion Power has recorded the estimated liability for the remediation costs of $8 million and $7 million, respectively, which it expects to pay out through 2008.

Under a separate consent order issued by the NYSDEC in 2000, Orion Power is required to evaluate certain technical changes to modify the intake cooling system of one of its plants. Orion Power and the NYSDEC will discuss the technical changes to be implemented. Depending on the outcome of these discussions, including the form of technology ultimately selected, Orion Power estimates that capital expenditures necessary to comply with the order could equal or exceed $87 million. Orion Power expects to begin construction on a portion of the cooling water intake in 2004.

Orion Power is responsible for environmental liabilities associated with the future closure of three ash disposal sites in Pennsylvania. As of December 31, 2002 and 2003, the total estimated liability determined by management with assistance from third-party engineers and recorded by Orion Power for these disposal sites was $14 million and $11 million, respectively, of which $1 million is to be paid over the next five years.

New Source Review Matters. The United States Environmental Protection Agency (EPA) has requested information from two Orion Power facilities, related to work activities conducted at the sites that may be associated with various permitting requirements of the Clean Air Act. Orion Power has responded to the EPA's requests for information. Furthermore, the New York state attorney general's office recently requested from the EPA a copy of all such correspondence relating to all facilities, which the EPA granted.

Other Matters. Orion Power is involved in a number of other legal, environmental and other proceedings before courts and governmental agencies. Although Orion Power cannot predict the outcome of these proceedings, Orion Power believes that the effects on the financial statements, if any, from the disposition of these matters will not have a material adverse effect on its results of operations, financial condition or cash flows.

(b) Tolling Agreement for Liberty's Generating Station.

LEP owns a 530 MW combined cycle gas fired power generation facility (the Liberty generating station). Liberty financed the construction costs of the Liberty generating station with borrowings under a credit agreement of which $262 million is outstanding as of December 31, 2003. Borrowings under the credit agreement, which are non-recourse to Orion Power and its affiliates (other than LEP and Liberty), are secured by pledges of the assets of the Liberty generating station and of the ownership interest in LEP. See note 7(a).

In July 2003, the counterparty to the tolling agreement under which LEP sold the generation output of the Liberty generation station filed for bankruptcy. Subsequently, a federal bankruptcy court issued an order that terminated the tolling agreement and triggered another event of default under the Liberty credit agreement. The default under the Liberty credit agreement, and the possible foreclosure by the lenders upon the assets of the Liberty generating station, do not constitute an event of default under any other debt agreements of Orion Power or its affiliates.

To date, the lenders under the Liberty credit agreement have not foreclosed upon the Liberty generating station. However, there can be no assurance that the lenders will continue to refrain from exercising such rights. If the lenders elect to foreclose on LEP, Liberty and/or the Liberty generating station, Orion Power could incur a pre-tax loss of an amount up to Orion Power's recorded net book value, with the potential of an additional loss due to an impairment of goodwill to be allocated to LEP. As of December 31, 2003, the combined net book value of LEP and Liberty was $346 million, excluding the non-recourse debt obligations of $262 million. At December 31, 2002 and 2003, Orion Power evaluated the Liberty generating station and the related intangible asset for the terminated tolling agreement for impairment. Based on the analyses, there were no impairments.

In September 2003, LEP sued the corporate guarantor of the counterparty to the tolling agreement, Gas Transmission Northwest Corporation, seeking payment of $140 million (the maximum amount of the guarantee) out of the $177 million termination claim calculated by LEP under the agreement. Subsequently, the counterparty to the tolling agreement and its corporate guarantors countersued LEP seeking to collect a $108 million termination payment under the tolling agreement. The obligations of LEP under the tolling agreement are secured by a $35 million letter of credit issued under the senior secured revolver of Reliant Resources. If the letter of credit were to be drawn, Reliant Resources would be required to reimburse the issuing bank.

In light of current market conditions and the termination of the tolling agreement, LEP does not expect to have sufficient cash flow to pay both (a) all of its expenses and to post the collateral required to buy fuel or in respect of the gas transportation agreements and (b) debt service obligations. Liberty received temporary deferrals until April 2004 from its lenders for the quarterly principal installments that were due in October 2003 and January 2004, which aggregated $4 million. Based on the foregoing, Orion Power is exploring various strategic options with respect to its subsidiaries' interest in the Liberty generating station, including, among other things, the execution of a foreclosure arrangement with the lenders resulting in a transfer of ownership to the lenders or a sale of Orion Power's interest in the generating station. There can be no assurances regarding the outcome of this process. A foreclosure of Orion Power's interest in the generation station would, however, result in an impairment of the asset on the balance sheet.

If LEP recovers the amount of the termination claim, the lenders are entitled to require that such amounts be used to pay deferred interest and to prepay debt under the Liberty credit agreement. Under United States and Pennsylvania tax laws, it is possible that receipt of a termination payment by LEP could be deemed taxable income to Orion Power Holdings and its other subsidiaries.

(15) Estimated Fair Value of Financial Instruments

The fair values of financial instruments, including cash and cash equivalents and derivative assets and liabilities (see note 6), are equivalent to their carrying amounts in the consolidated balance sheets. The fair values of derivative assets and liabilities as of December 31, 2002 and 2003 have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques, see note 6.

The carrying values and related fair market values of Orion Power's short-term and long-term debt are detailed as follows (excluding adjustment to fair value of interest rate swaps and debt under Liberty's credit agreement):

	December 31,			
	2002		2003	
	Carrying Value(1)	Fair Market Value(1)(2)(3)	Carrying Value(1)	Fair Market Value(1)(3)
	(In millions)			
Fixed rate debt	$ 475	$323	$ 467	$ 488
Floating rate debt	1,371	N/A	1,218	1,218
Total debt, excluding adjustment to fair value of interest rate swaps and Liberty's debt	$1,846	N/A	$1,685	$1,706

(1) Excludes Liberty's fixed rate debt of $165 million and floating rate debt of $103 million and $97 million as of December 31, 2002 and 2003, respectively, as there was no active market for this debt. Due to the situation with Liberty (see note 14(c)), if the holders of Liberty's debt were to have tried to sell such debt instrument to a third party, the price which could have been realized would likely be substantially less than the face value of the debt instrument and substantially less than the carrying value.

(2) As of December 31, 2002, Orion Power had floating rate debt with a carrying value of $1.4 billion, excluding adjustment to fair value of interest rate swaps and Liberty's debt. There was no active market for Orion Power's floating rate debt obligations as of December 31, 2002. Given the liquidity and credit situation as of December 31, 2002, if the holders of these borrowings were to have tried to sell such debt instruments to third parties, the prices which could have been realized could have been substantially less than the face values of the debt instruments and substantially less than Orion Power's carrying values.

(3) The fair market values of the fixed rate debt (December 31, 2002 and 2003) and floating rate debt (for December 31, 2003 only) were based on (a) Reliant Resources' incremental borrowing rates for similar types of borrowing arrangements or (b) information from market participants. For $1.2 billion of our floating rate debt, the carrying value equals the fair market value as of December 31, 2003.

(16) Unaudited Quarterly Information

Summarized unaudited quarterly information is as follows:

	Former Orion	Current Orion			
	January 1, 2002 through February 19, 2002	February 20, 2002 through March 31, 2002	Quarter Ended June 30, 2002	Quarter Ended September 30, 2002	Quarter Ended December 31, 2002
	(In thousands)	(In thousands)			
Operating revenues	$122,408	$113,009	$290,445	$420,640	$ 197,949
Operating (loss) income	(66,819)	32,207	82,152	139,986	(351,268)
Net (loss) income	(52,174)	13,090	27,558	61,370	(359,434)

	Current Orion			
	Quarter Ended March 31, 2003	Quarter Ended June 30, 2003	Quarter Ended September 30, 2003	Quarter Ended December 31, 2003
	(In thousands)			
Operating revenues	$279,669	$267,012	$ 404,116	$264,518
Operating income (loss)	29,039	35,504	(474,779)	(4,775)
Cumulative effect of accounting change, net of tax	2,121	—	—	—
Net income (loss)	185	1,391	(537,377)	(19,884)

The variances in revenues from quarter to quarter for 2002 and 2003 were primarily due to (a) the Merger and the related purchase accounting, see note 1, (b) the seasonal fluctuations in demand for electric energy and energy services and (c) changes in energy commodity prices. Changes in operating income (loss) and net income (loss) from quarter to quarter for 2002 and 2003 were primarily due to:

- the seasonal fluctuations in demand for electric energy and energy services;
- $2 million, net of tax, cumulative effect of accounting change primarily in the first quarter of 2003 (only impacted net loss) (see note 2(p));
- the impact of an increase in allocated general and administrative costs from affiliate;
- changes in energy commodity prices; and
- the timing of maintenance expenses on electric generation plants.

In addition, operating income (loss) and net income (loss) changed from quarter to quarter in 2002 by:

- the impact of the Merger (see note 4);
- costs related to plant cancellations and equipment impairments in 2002; and
- $338 million goodwill impairment in the fourth quarter of 2002 (see note 5).
- Also, operating income (loss) and net income (loss) changed from quarter to quarter in 2003 by the $585 million goodwill impairment in the third quarter of 2003 (see note 5).

* * *

The following is a copy of a report previously issued by Arthur Andersen LLP (Andersen). The report has not been reissued by Andersen.

Report of Independent Public Accountants

To Orion Power Holdings, Inc.:

We have audited in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of Orion Power Holdings, Inc. and subsidiaries, incorporated by reference in this Form 10-K, and have issued our report thereon dated February 19, 2002. Our audit was made for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The schedule listed in the index of financial statements is the responsibility of the company's management and is presented for the purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic consolidated financial statements. This schedule has been subjected to the auditing procedures applied in the audit of the basic consolidated financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

/s/ Arthur Andersen LLP

Vienna, Virginia
February 19, 2002

ORION POWER HOLDINGS, INC.

CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF OPERATIONS

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February 20, 2002 through December 31, 2002	Year Ended December 31, 2003
	(Thousands of dollars)			
(Expenses) Income:				
General, administrative and development	$(22,908)	$(49,799)	$ (10,275)	$ (2,940)
Depreciation and amortization	(1,278)	(119)	—	(75)
Equity in earnings (loss) of investments in subsidiaries and impairment of goodwill	188,266	(18,972)	(229,891)	(529,041)
Interest expense	(56,172)	(8,215)	(39,371)	(40,807)
Interest income	9,435	360	1,877	54
Income (Loss) Before Income Taxes	117,343	(76,745)	(277,660)	(572,809)
Income tax expense (benefit)	16,740	(24,571)	(20,244)	(17,124)
Net Income (Loss)	$100,603	$(52,174)	$(257,416)	$(555,685)

See Notes to the Condensed Financial Statements and Orion Power's Consolidated Financial Statements

ORION POWER HOLDINGS, INC.

CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS

	December 31, 2002	December 31, 2003
	(Thousands of dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 6,220	$ 32,786
State income taxes receivable	45,458	21,883
Accumulated deferred income taxes	973	3,226
Other	371	434
Total current assets	53,022	58,329
Property, Plant and Equipment, net	504	664
Other Assets:		
Investment in subsidiaries and goodwill, net	3,282,695	2,820,926
Accumulated deferred income taxes	32,549	25,667
Other	1,050	793
Total other assets	3,316,294	2,847,386
Total Assets	$3,369,820	$2,906,379
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 7,506	$ 8,139
Accounts payable	69	135
Payable to affiliates, net	7,889	7,937
Accrued expenses	4,965	4,909
Accrued interest	8,000	8,000
Total current liabilities	28,429	29,120
Long-term Debt	465,821	457,681
Other	3,737	4,101
Total Liabilities	497,987	490,902
Stockholder's Equity:		
Common stock; par value $1.00 per share (1,000 shares authorized, issued and outstanding)	1	1
Additional paid-in capital	3,152,701	3,233,308
Retained deficit	(257,416)	(813,101)
Accumulated other comprehensive loss	(23,453)	(4,731)
Stockholder's Equity	2,871,833	2,415,477
Total Liabilities and Stockholder's Equity	$3,369,820	$2,906,379

See Notes to the Condensed Financial Statements and Orion Power's Consolidated Financial Statements

ORION POWER HOLDINGS, INC.

CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS

	Former Orion		Current Orion	
	Year Ended December 31, 2001	January 1, 2002 through February 19, 2002	February, 20 2002 through December 31, 2002	Year Ended December 31, 2003
	(Thousands of dollars)			
Cash Flows from Operating Activities:				
Net income (loss)	$ 100,603	$(52,174)	$(257,416)	$(555,685)
Adjustments to reconcile net income (loss) to net cash (used in) provided by operating activities:				
Depreciation and amortization	1,278	119	—	75
Deferred income taxes	16,740	48,767	2,132	19,669
Equity in (earnings) loss of investment in subsidiaries and impairment of goodwill	(188,266)	18,972	229,891	529,041
Amortization of deferred financing fees	2,498	317	—	—
Amortization of the revaluation of debt	—	—	(5,927)	(7,506)
Deferred compensation	1,596	1,763	—	—
Interest income on officers' notes receivable	2,180	—	—	—
Federal income taxes payable	—	—	(17,737)	(951)
Change in assets and liabilities:				
Restricted cash	(518)	(583)	1,101	—
Receivable from affiliates, net	(82,006)	(66,559)	57,253	(153)
Income taxes receivable	—	(33,947)	(45,458)	23,575
Other assets	1,101	495	480	(18)
Accounts payable	(182)	14,618	(15,601)	66
Accrued expenses	(7,843)	2,308	2,099	306
Accrued interest	725	7,758	8,000	—
Net cash (used in) provided by operating activities	(152,094)	(58,146)	(41,183)	8,419
Cash Flows from Investing Activities:				
Purchase of property, equipment and related assets in acquisition, net	(1,518)	(112)	(504)	(235)
Distributions received from subsidiaries	86,466	—	—	831
Investment made in subsidiaries	(364,728)	(37,944)	(75,557)	(17,449)
Net cash used in investing activities	(279,780)	(38,056)	(76,061)	(16,853)
Cash Flows from Financing Activities:				
Proceeds from long-term debt	200,000	—	60,000	—
Payments on long-term debt	—	—	(260,000)	—
Proceeds from issuance of common stock, net	273,530	491	—	—
Contributions from stockholder	—	—	246,832	35,000
Payment on officers' notes receivable	—	3,736	—	—
Payments of deferred financing fees	(6,702)	—	—	—
Net cash provided by financing activities	466,828	4,227	46,832	35,000
Net Change in Cash and Equivalents	34,954	(91,975)	(70,412)	26,566
Cash and Cash Equivalents, Beginning of Period	133,653	168,607	76,632	6,220
Cash and Cash Equivalents, End of Period	$ 168,607	$ 76,632	$ 6,220	$ 32,786
Supplemental Disclosure of Cash Flow Information:				
Cash payments:				
Interest paid	$ 52,949	$ —	$ 50,942	$ 48,000
Income taxes paid (net of income tax refunds received)	—	—	—	(59,417)

See Notes to the Condensed Financial Statements and Orion Power's Consolidated Financial Statements

ORION POWER HOLDINGS, INC.

CONDENSED FINANCIAL INFORMATION
NOTES TO CONDENSED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

These condensed parent company financial statements have been prepared in accordance with Rule 12-04, Schedule 1 of Regulation S-X, as the restricted net assets of Orion Power Holdings, Inc.'s . (Orion Power Holdings) subsidiaries exceed 25% of the consolidated net assets of Orion Power Holdings. This information should be read in conjunction with the Orion Power Holdings and subsidiaries (Orion Power) consolidated financial statements included elsewhere in this filing.

Orion Power Holdings' 100% investments in its subsidiaries have been recorded using the equity basis of accounting in the accompanying condensed parent company financial statements. Included in equity in earnings (loss) of investments in subsidiaries in 2003 is a cumulative effect of accounting change for a new accounting pronouncement as more fully described in note 2(p) to Orion Power's consolidated financial statements.

Some amounts from the previous years have been reclassified to conform to the 2003 presentation of condensed financial information. These reclassifications do not affect earnings.

For the 2001 cash flow statement, Orion Power Holdings has presented amortization of deferred financing fees separately from depreciation and amortization.

(2) Contributions from Stockholder

In May 2003 and November 2003, Reliant Resources, Inc. (Reliant Resources) contributed $15 million and $20 million, respectively, to Orion Power Holdings, as a partial funding of the semi-annual interest payment of $24 million on the senior notes due in each of May 2003 and November 2003. While Reliant Resources has no obligation, it intends to contribute any funding shortfall for the semi-annual interest payments due in May 2004 and November 2004 should Orion Power Holdings' funds be insufficient. See notes 3 and 7 to Orion Power's consolidated financial statements.

(3) Restricted Net Assets of Subsidiaries

Certain of Orion Power Holdings' subsidiaries have effective restrictions on their ability to pay dividends or make intercompany loans and advances pursuant to their financing arrangements. The amount of restricted net assets of Orion Power Holdings' subsidiaries at December 31, 2002 and 2003 is approximately $2.2 billion and $2.7 billion, respectively. Such restrictions are on the net assets of Orion Power Capital, LLC Liberty Electric PA, LLC and Liberty Electric Power, LLC. Orion Power Midwest, LP and Orion Power New York, LP are indirect wholly-owned subsidiaries of Orion Power Capital, LLC.

(4) Debt Facilities

For a discussion of Orion Power Holdings' senior notes, which are due in 2010, see note 7 to Orion Power's consolidated financial statements.

(5) Commitments and Contingencies

(a) Guarantees

Orion Power Holdings has issued guarantees in conjunction with certain performance agreements and commodity and derivative contracts and other contracts that provide financial assurance to third parties on behalf of a subsidiary. The guarantees on behalf of subsidiaries are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the relevant subsidiary's intended commercial purposes.

The following tables detail Orion Power Holdings' various guarantees, including the maximum potential amounts of future payments, assets held as collateral and the carrying amount of the liabilities recorded on the balance sheets, if applicable:

	December 31, 2002		
Type of Guarantee	Maximum Potential Amount of Future Payments	Assets Held as Collateral	Carrying Amount of Liability Recorded on Balance Sheet
		(In millions)	
Guarantees under Reliant Resources' debt(1)	$1,100	$—	$—
Hedging obligations(2)	2	—	—
Payment and performance obligations under service contracts(3)	26	—	—
Total guarantees	$1,128	$—	$—

	December 31, 2003		
Type of Guarantee	Maximum Potential Amount of Future Payments	Assets Held as Collateral	Carrying Amount of Liability Recorded on Balance Sheet
		(In millions)	
Guarantees under Reliant Resources' debt	$1,100	$—	$—
Hedging obligations(2)	2	—	—
Total guarantees	$1,102	$—	$—

(1) Orion Power Holdings has guaranteed Reliant Resources' March 2003 credit facility and senior secured notes. The related debt matures at varying dates from 2007 to 2013.

(2) Orion Power Holdings has guaranteed the performance of certain of its wholly-owned subsidiaries' hedging obligations. These guarantees were provided to counterparties in order to facilitate physical and financial agreements in fuel and emissions. As of December 31, 2003, the expiration of certain guarantees was not yet determinable, as they are ongoing. The fair values of the underlying transactions are included in Orion Power Holdings' subsidiaries' balance sheets.

(3) Orion Power Holdings has guaranteed the payment obligations of certain wholly-owned subsidiaries arising under long-term service agreements. These guarantees have varying expiration dates. As of December 31, 2002, guarantees with determinable expiration dates expire over varying year's through December 2014. As of December 31, 2003, the expiration date of certain guarantees was not yet determinable.

Unless otherwise noted, failure by the primary obligor to perform under the terms of the various agreements and contracts guaranteed may result in the beneficiary requesting immediate payment from Orion Power Holdings. To the extent liabilities exist under the various agreements and contracts that Orion Power Holdings guarantees, such liabilities are recorded in Orion Power Holdings' subsidiaries' balance sheets at December 31, 2003. Management believes the likelihood that Orion Power Holdings would be required to perform or otherwise incur any significant losses associated with any of these guarantees is remote.

Together with certain of Reliant Resources' other subsidiaries, Orion Power Holdings is a guarantor of the obligations under Reliant Resources' Amended and Restated Credit and Guaranty Agreement dated as of March 28, 2003, subject to certain limitations under the Orion Power Holdings' senior notes. These limitations limit the amount of Orion Power Holdings' guarantee based on a fixed charge coverage ratio, consolidated tangible assets and a restricted payment ceiling test, under the Orion Power Holdings' senior notes. Additionally, Orion Power Holdings is the only limited guarantor of the obligations under Reliant

Resources' senior secured notes issued in July 2003, subject to the same limitations. None of Orion Power Holdings' subsidiaries guarantee Reliant Resources' senior secured notes.

Both Reliant Resources' March 2003 credit facility and its senior secured notes restrict Orion Power Holdings' and its subsidiaries' ability to take specific actions, subject to numerous exceptions that are designed to allow for the execution of Reliant Resources' and its subsidiaries' business plans in the ordinary course, including the preservation and optimization of existing investments in the retail energy and wholesale energy businesses and the ability to provide credit support for commercial obligations. See note 13(e) to Orion Power's consolidated financial statements.

(b) Leases

Orion Power Holdings has entered in various non-cancelable operating lease arrangements for office space and storage space. These leases terminate in 2005. Future minimum payments due under these leases are as follows (in thousands):

2004	$340
2005	173
	$513

Total rental expense for 2001, January 1, 2002 through February 19, 2002, February 20, 2002 through December 31, 2002 and 2003 was $377,000, $43,000, $275,000 and $445,000, respectively.

(6) Cash Distributions

Orion Power New York, L.P. made cash distributions to Orion Power Holdings in 2001 of $86 million and in 2002 as part of a refinancing, repaid a $60 million revolving senior credit facility on behalf of Orion Power Holdings, which was deemed a distribution to Orion Power Holdings (see note 7 to Orion Power's consolidated financial statements). No dividends or distributions had been made to Orion Power Holdings by Orion Power New York, L.P. in 2002 or 2003. No dividends or distributions had been made to Orion Power Holdings by Orion Power MidWest, L.P. or Liberty Electric Power, LLC through December 31, 2003. Orion Power Development Company, Inc. distributed $831,000 to Orion Power Holdings in 2003. See note 7 to Orion Power's consolidated financial statements regarding restrictions on cash distributions from Orion Power Holdings' subsidiaries to Orion Power Holdings.

* * *

ORION POWER HOLDINGS, INC. AND SUBSIDIARIES

RESERVES

For the Period February 20, 2002 through December 31, 2002 and the Year Ended December 31, 2003

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts(1)	Deductions from Reserves(2)	Balance at End of Period
	(Thousands of dollars)				
For the Period February 20, 2002 through December 31, 2002:					
Accumulated provisions:					
Uncollectible accounts receivable	$ —	$ 951	$ 989	$ —	$1,940
Reserves for inventory	—	—	208	—	208
Deferred tax assets valuation	—	—	29,714	—	29,714
For the Year Ended December 31, 2003:					
Accumulated provisions:					
Uncollectible accounts receivable	1,940	6,164	—	(989)	7,115
Reserves for inventory	208	—		—	208
Deferred tax assets valuation	29,714	3,831	—	—	33,545

(1) Charged to other accounts represents obligations established related to Reliant Resources, Inc.'s acquisition of Orion Power Holdings, Inc. and its subsidiaries.

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

* * *

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

None.

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

Evaluation of Disclosure Controls and Procedures

Our chief executive officer and chief financial officer have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based on such evaluation, such officers have concluded that, as of the end of such period, our disclosure controls and procedures are effective in alerting them on a timely basis to material information required to be included in our reports filed or submitted under the Securities Exchange Act of 1934.

Changes in Internal Controls

In connection with the evaluation described above, we identified no change in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during our fiscal quarter ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART III

Item 10. ***Directors and Executive Officers.***

The information called for by Item 10, to the extent not set forth in "Executive Officers" in Item 1, will be set forth in the definitive proxy statement relating to our 2004 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 11. ***Executive Compensation.***

The information called for by Item 11 will be set forth in the definitive proxy statement relating to our 2004 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 12 will be set forth in the definitive proxy statement relating to our 2004 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 13. ***Certain Relationships and Related Transactions.***

The information called for by Item 13 will be set forth in the definitive proxy statement relating to our 2004 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 14 will be set forth in the definitive proxy statement relating to our 2004 annual meeting of stockholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of stockholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K.***

(a) (1) Reliant Resources, Inc. and Subsidiaries Financial Statements.

Responsibility for Financial Reporting F-2
Independent Auditors' Report F-3
Consolidated Statements of Operations for the Years Ended December 31, 2001, 2002 and 2003 . . F-4
Consolidated Balance Sheets as of December 31, 2002 and 2003 . . . . . F-5
Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2002 and 2003 F-6
Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2001, 2002 and 2003 . . . . . F-7
Notes to Consolidated Financial Statements F-10

(a) (2) Financial Statement Schedules.

Schedule I — Condensed Financial Information of Reliant Resources, Inc.
Condensed Statements of Operations for the Years Ended December 31, 2001, 2002 and 2003 . . . . F-107
Condensed Balance Sheets as of December 31, 2002 and 2003 . . . . . F-108
Condensed Statements of Cash Flows for the Years Ended December 31, 2001, 2002 and 2003 . . . F-109
Notes to Condensed Financial Statements F-111
Schedule II — Reliant Resources, Inc. and Subsidiaries — Reserves for the Three Years Ended December 31, 2003 . . . . . F-116

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements: III, IV and V.

The following financial statements are included in this report pursuant to Items 3-10 or 3-16 of Regulation S-X:

Reliant Energy Retail Holdings, LLC and Subsidiaries Financial Statements.

Independent Auditors' Report F-118
Consolidated Statements of Operations for the Years Ended December 31, 2001, 2002 and 2003 . . F-119
Consolidated Balance Sheets as of December 31, 2002 and 2003 . . . . . F-120
Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2002 and 2003 F-121
Consolidated Statements of Member's (Deficit) Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2001, 2002 and 2003 . . . . . F-122
Notes to Consolidated Financial Statements F-123

Reliant Energy Mid-Atlantic Power Holdings, LLC and Subsidiaries Financial Statements.

Independent Auditors' Report F-149
Consolidated Statements of Operations for the Years Ended December 31, 2001, 2002 and 2003 . . F-150
Consolidated Balance Sheets as of December 31, 2002 and 2003 . . . . . F-151
Consolidated Statements of Cash Flows for the Years Ended December 31, 2001, 2002 and 2003 F-152
Consolidated Statements of Shareholder's Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2001, 2002 and 2003 . . . . . F-153
Notes to Consolidated Financial Statements F-154

Orion Power Holdings, Inc. and Subsidiaries Financial Statements.

Independent Auditors' Reports F-178

Consolidated Statements of Operations for the Year Ended December 31, 2001, for the Periods from January 1, 2002 through February 19, 2002 and February 20, 2002 through December 31, 2002 and for the Year Ended December 31, 2003 . . . . . F-181

Consolidated Balance Sheets as of December 31, 2002 and 2003 . . . . . F-182

Consolidated Statements of Cash Flows for the Year Ended December 31, 2001, for the Periods from January 1, 2002 through February 19, 2002 and February 20, 2002 through December 31, 2002 and for the Year Ended December 31, 2003 . . . . . F-183

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss) for the Year Ended December 31, 2001, for the Periods from January 1, 2002 through February 19, 2002 and February 20, 2002 through December 31, 2002 and for the Year Ended December 31, 2003 . . . . F-184

Notes to Consolidated Financial Statements F-185

Condensed Financial Information of Orion Power Holdings, Inc. F-227

(a) (3) Exhibits

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

(b) Reports on Form 8-K.

- Reliant Resources' Current Report (item 12) on Form 8-K filed on November 10, 2003;
- Reliant Resources' Current Report (items 5 and 7) on Form 8-K filed on November 14, 2003;
- Reliant Resources' Current Report (item 9) on Form 8-K filed on November 14, 2003;
- Reliant Resources' Current Report (item 9) on Form 8-K filed on November 21, 2003;
- Reliant Resources' Current Report (items 5 and 7) on Form 8-K filed on November 26, 2003;
- Reliant Resources' Current Report (items 5 and 7) on Form 8-K filed on December 9, 2003;
- Reliant Resources' Current Report (items 2 and 7) on Form 8-K filed on December 22, 2003; and
- Reliant Resources' Current Report (items 5 and 7) on Form 8-K filed on December 29, 2003.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

RELIANT RESOURCES, INC.

By: /s/ JOEL V. STAFF

Joel V. Staff
Chairman and Chief Executive Officer
March 8, 2004

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ JOEL V. STAFF Joel V. Staff	Chairman and Chief Executive Officer (Principal Executive Officer)	March 8, 2004
/s/ MARK M. JACOBS Mark M. Jacobs	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 8, 2004
/s/ THOMAS C. LIVENGOOD Thomas C. Livengood	Vice President and Controller (Principal Accounting Officer)	March 8, 2004
/s/ E. WILLIAM BARNETT E. William Barnett	Director	March 8, 2004
/s/ DONALD J. BREEDING Donald J. Breeding	Director	March 8, 2004
/s/ KIRBYJON H. CALDWELL Kirbyjon H. Caldwell	Director	March 8, 2004
/s/ STEVEN L. MILLER Steven L. Miller	Director	March 8, 2004
/s/ LAREE E. PEREZ Laree E. Perez	Director	March 8, 2004
/s/ WILLIAM L. TRANSIER William L. Transier	Director	March 8, 2004

INDEX OF EXHIBITS

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated by an asterisk (*) are management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.1	Restated Certificate of Incorporation	Reliant Resources, Inc.'s Registration Statement on Form S-1, dated October 16, 2000	333-48038	3.1
3.2	Amended and Restated Bylaws	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2001	1-16455	3
4.1	Specimen Stock Certificate	Reliant Resources, Inc.'s Registration Statement on Form S-1, dated October 16, 2000	333-48038	4.1
4.2	Rights Agreement effective as of January 15, 2001 between Reliant Resources, Inc. and The Chase Manhattan Bank, as Rights Agent, including a form of Rights Certificate	Amendment No. 4 to Registration Statement on Form S-1, dated January 18, 2001	333-48038	4.2
4.3	Warrant Agreement, dated as of March 28, 2003, by Reliant Resources, Inc. for the benefit of the holders from time to time	Reliant Resources, Inc.'s Amendment No. 1 to Annual Report on Form 10-K/A for the year ended December 31, 2002	333-48038	4.3
4.4	Indenture relating to 5.00% Convertible Senior Subordinated Notes due 2010, dated as of June 24, 2003, between Reliant Resources, Inc. and Wilmington Trust Company, as Trustee	Reliant Resources, Inc.'s Registration Statement on Form S-3, dated July 24, 2003	333-107295	4.5
4.5	Registration Rights Agreement dated as of June 24, 2003 among Reliant Resources, Inc., Deutsche Bank Securities Inc., Goldman, Sachs & Co, and Banc of America Securities LLC	Reliant Resources, Inc.'s Registration Statement on Form S-3, dated July 24, 2003	333-107295	4.7
4.6	Indenture relating to the 9.25% Senior Secured Notes due 2010, dated as of July 1, 2003, among Reliant Resources, Inc., the Guarantors listed in Schedule I thereto and Wilmington Trust Company, as Trustee	Reliant Resources, Inc.'s Registration Statement on Form S-4, dated July 24, 2003	333-107297	4.5

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4.7	Indenture relating to the 9.50% Senior Secured Notes due 2013, dated as of July 1, 2003, among Reliant Resources, Inc., the Guarantors listed in Schedule I thereto and Wilmington Trust Company, as Trustee	Reliant Resources, Inc.'s Registration Statement on Form S-4, dated July 24, 2003	333-107297	4.7
4.8	Registration Rights Agreement dated as of July 1, 2003 among Reliant Resources, Inc., Banc of America Securities LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co. and Barclays Capital, Inc.	Reliant Resources, Inc.'s Registration Statement on Form S-4, dated July 24, 2003	333-107297	4.9
4.9	Form of Senior Indenture to be issued under universal shelf	Reliant Resources, Inc.'s Amendment No. 1 to Registration Statement on Form S-3, dated December 10, 2003	333-107296	4.5
4.10	Form of Subordinated Indenture to be issued under universal shelf	Reliant Resources, Inc.'s Amendment No. 1 to Registration Statement on Form S-3, dated December 10, 2003	333-107296	4.6
10.1	Master Separation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated dated December 31, 2000	Reliant Energy, Incorporated's (now known as CenterPoint Energy Houston Electric, LLC's) Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2001	1-3187	10.1
10.2	Transition Services Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated December 31, 2000	Reliant Energy, Incorporated's (now known as CenterPoint Energy Houston Electric, LLC's) Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2001	1-3187	10.2
10.3	Technical Services Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated (now known as CenterPoint Energy Houston Electric, LLC's), dated December 31, 2000	Reliant Energy, Incorporated's (now known as CenterPoint Energy Houston Electric, LLC's) Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2001	1-3187	10.3
+*10.4	Severance Agreement between Reliant Resources, Inc. and James B. Robb, dated January 14, 2003			

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
+*10.5	First Amendment to Reliant Resources, Inc. Deferral Plan, effective January 14, 2003			
10.6	Tax Allocation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated (now known as CenterPoint Energy Houston Electric, LLC's), dated December 31, 2000	Reliant Energy, Incorporated's (now known as CenterPoint Energy Houston Electric, LLC's) Quarterly Report on Form 10-Q for the Quarterly Period Ended March 31, 2001	1-3187	10.8
10.7	Purchase Agreement dated as of February 19, 2000 among Reliant Energy Power Generation, Reliant Energy Sithe Energies, Inc. and Sithe Northeast Generating Company, Inc.	Reliant Energy, Incorporated's (now known as CenterPoint Energy Houston Electric, LLC's) Annual Report on Form 10-K for the year ended December 31, 1999	1-3187	10.3
10.8	Reliant Resources, Inc. Employee Stock Purchase Plan	Reliant Resources, Inc.'s Registration Statement on Form S-8	333-60124	4.5
*10.9	Reliant Resources, Inc. Annual Incentive Compensation Plan effective January 1, 2001	Reliant Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.9
*10.10	Reliant Resources, Inc. 2002 Annual Incentive Compensation Plan for Executive Officers, effective March 1, 2002	Reliant Resources, Inc.'s 2002 Proxy Statement on Schedule 14A	1-16455	Appendix I
*10.11	Long Term Incentive Plan of Reliant Resources, Inc. effective January 1, 2001	Reliant Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.10
*10.12	Reliant Resources, Inc. 2002 Long-Term Incentive Plan	Reliant Resources, Inc.'s 2002 Proxy Statement on Schedule 14A	1-16455	Appendix II
*10.13	Reliant Resources, Inc. 2002 Stock Plan, effective March 1, 2002	Reliant Resources, Inc.'s Registration Statement on Form S-8	333-86610	4.5
*10.14	Reliant Resources, Inc. Deferral Plan, effective January 1, 2002, First Amendment effective January 14, 2003	Reliant Resources, Inc.'s Registration Statement on Form S-8	333-74790	4.1
+*10.15	Amendment No. 1 to Employee Matters Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated (now known as CenterPoint Energy Houston Electric, LLC's), dated December 31, 2000			
*10.16	Reliant Resources, Inc. Savings Plan, effective February 1, 2002	Reliant Resources, Inc.'s Registration Statement on Form S-8	333-74754	4.5
*10.17	Reliant Resources, Inc. Union Savings Plan, effective January 2, 2002	Reliant Resources, Inc.'s Registration Statement on Form S-8	333-74754	4.5

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10.18	Reliant Resources, Inc.'s Executive Benefits Plan effective June 1, 1982, including the first, second and third amendments thereto (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to some of its officers)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.11
*10.19	Reliant Resources, Inc.'s Benefit Restoration Plan, as amended and restated effective July 1, 1991, including the first amendment thereto (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to some of its employees)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.12
10.20	Facility Lease Agreement dated as of August 14, 2000 between Conemaugh Lessor Genco LLC and Reliant Energy Mid-Atlantic Power Holding, LLC	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.6a
10.21	Schedule identifying substantially identical agreements to Facility Lease Agreement constituting Exhibit 10.20	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.6b
10.22	Series A Pass Through Trust Agreement dated as of August 24, 2000 between Reliant Energy Mid-Atlantic Power Holding, LLC and Bankers Trust Company, made with respect to the formation of the Series A Pass Through Trust and the issuance of Series A Pass Through Certificates	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.4a
10.23	Schedule identifying substantially identical agreements to Pass Through Trust Agreement constituting Exhibit 10.22	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.4b

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.24	Participation Agreement dated as of August 24, 2000 among Conemaugh Lessor Genco LLC, as Owner Lessor, Reliant Energy Mid-Atlantic Power Holding, LLC, as Facility Lessee, Wilmington Trust Company, as Lessor Manager, PSEGR Conemaugh Generation, LLC, as Owner Participant, Bankers Trust Company, as Lease Indenture Trustee, and Bankers Trust Company, as Pass Through Trustee	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.5a
10.25	Schedule Identifying substantially identical agreements to Participation Agreement constituting Exhibit 10.24	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.5b
10.26	Lease Indenture of Trust, Mortgage and Security Agreement dated as of August 24, 2000 between Conemaugh Lessor Genco LLC and Bankers Trust Company	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.8a
10.27	Schedule identifying substantially identical agreements to Lease Indenture of Trust constituting Exhibit 10.26	Reliant Energy Mid-Atlantic Power Holding, LLC's Registration Statement on Form S-4	333-51464	4.8b
*10.28	Reliant Resources, Inc.'s Deferred Compensation Plan effective as of September 1, 1985, including the first nine amendments thereto (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to some of its employees)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.25

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10.29	Reliant Resources, Inc.'s Deferred Compensation Plan, as amended and restated effective January 1, 1989, including the first nine amendments (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to some of its employees)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.26
*10.30	Reliant Resources, Inc.'s Deferred Compensation Plan, as amended and restated effective January 1, 1991, including the first ten amendments thereto (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to some of its employees)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.27
*10.31	Reliant Resources, Inc.'s Savings Restoration Plan effective January 1, 1991, including the first and second amendments thereto (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to some of its employees)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.28
*10.32	Reliant Resources, Inc.'s Director Benefits Plan effective January 1, 1992, including the first amendment thereto (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to members of its board of directors)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.29

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10.33	Reliant Resources, Inc.'s Executive Life Insurance Plan effective January 1, 1994, including the first and second amendments thereto (this plan is a former plan of Reliant Energy, Incorporated, now known as CenterPoint Energy Houston Electric, LLC, and Reliant Resources, Inc. has adopted certain obligations under this plan with respect to some of its officers)	Reliant Resources, Inc.'s Registration Statement on Form S-1	333-48038	10.30
10.34	Agreement Plan of Merger dated as of September 26, 2001 by and Among Orion Power Holdings, Inc., Reliant Resources, Inc. and Reliant Energy Power Generation Merger Sub, Inc.	Reliant Resources, Inc.'s Current Report on Form 8-K dated September 27, 2002	1-16455	2.1
*10.35	Retention Agreement effective May 4, 2001 between Reliant Resources, Inc. and Robert W. Harvey	Reliant Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.34
*10.36	Severance Agreement between Reliant Resources, Inc. and Robert W. Harvey, dated May 30, 2003	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003	1-16455	
*10.37	Reliant Resources, Inc. Transition Stock Plan, effective May 4, 2001	Reliant Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001	1-16455	10.37
*10.38	Employment Agreement effective July 29, 2002 between Reliant Resources, Inc. and Mark M. Jacobs	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2002	1-16455	10.1
*10.39	Severance Agreement between Reliant Resources, Inc. and Mark M. Jacobs, dated April 30, 2003	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003	1-16455	10.5
10.40	First Amendment to Employment Agreement between Reliant Resources, Inc. and Mark M. Jacobs, dated April 30, 2003	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003	1-16455	10.2
10.41	Severance Agreement between Reliant Resources, Inc. and Jerry J. Langdon, dated May 20, 2003	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2003	1-16455	10.1
10.42	Severance Agreement between Reliant Resources, Inc., Reliant Energy Corporate Services, LLC and Joel V. Staff, dated August 11, 2003	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2003	1-16455	10.4

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.43	Severance Agreement between Reliant Resources, Inc., Reliant Energy Corporate Services, LLC and Michael L. Jines, dated May 1, 2003	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2003	1-16455	10.6
10.44	Share Purchase Agreement, dated as of February 28, 2003, among Reliant Energy Europe Inc., Reliant Energy Wholesale (Europe) Holdings B.V., n.v. Nuon and Reliant Resources, Inc.	Reliant Resources, Inc.'s Current Report on Form 8-K, dated September 26, 2003	1-16455	99.3
10.45	Amended and Restated Credit and Guaranty Agreement, dated as of March 28, 2003, among (i) Reliant Resources, Inc., as a Borrower and Guarantor; (ii) the other Credit Parties referred to therein, as Borrowers and/or Guarantors; (iii) the Lenders referred to therein; (iv) Bank of America, N.A., as administrative agent for the Lenders, as Collateral Agent and as an Issuing Bank; (v) Barclays Bank PLC and Deutsche Bank AG, New York Branch, as syndication agents for the Lenders; (vi) Citicorp USA, Inc., as Tranche A Agent; and (vii) Citibank, N.A., as Tranche A Collateral Agent	Reliant Resources, Inc.'s Amendment No. 1 to its Annual Report on Form 10-K/A	1-6455	10.42
10.46	Intercreditor Agreement, dated as of March 28, 2003 between Bank of America, N.A. and Citibank USA, Inc. and Citibank, N.A.	Reliant Resources, Inc.'s Registration Statement on Form S-4, dated July 24, 2003	333-107297	10.44
10.47	Amendment No. 1 to First Amended and Restated Credit and Guaranty Agreement, dated as of June 16, 2003.	Reliant Resources, Inc.'s Registration Statement on Form S-4, dated July 24, 2003	333-107297	10.43

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.48	Amendment No. 2 dated as of December 29, 2003 to the Amended and Restated Credit and Guaranty Agreement dated as of March 28, 2003, as amended by Amendment No. 1 dated as of June 16, 2003 among Reliant Resources, Inc., as a Borrower and a Guarantor, the other credit parties referred to therein, as Borrowers and/or Guarantors, the lenders referred to therein, Bank of America, N.A., as Administrative Agent, as Collateral Agent and as an Issuing Bank, Barclays Bank LC and Deutsche Bank AG, New York Branch, as Syndication Agents, Citicorp USA, Inc., as Tranche A Agent and Citibank, N.A., as Tranche A Collateral Agent	Reliant Resources, Inc.'s Current Report on Form 8-K, dated December 29, 2003	1-16455	99.2
*10.49	Severance Agreement between Reliant Resources, Inc. and R. Steve Letbetter, dated January 14, 2003.	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003	1-16455	10.1
*10.50	Amendment to Severance Agreement between Reliant Resources, Inc. and R. Steve Letbetter, made and effective as of April 13, 2003	Reliant Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003	1-16455	10.2
+12.1	Reliant Resources, Inc. and Subsidiaries Ratio of Earnings from Continuing Operations to Fixed Charges			
+21.1	Subsidiaries of Reliant Resources, Inc.			
+23.1	Consent of Deloitte & Touche LLP			
+31.1	Certification of the Chairman and Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002			
+31.2	Certification of the Executive Vice President and Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002			

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
+32.1	Certification of Chairman and Chief Executive Officer of Reliant Resources, Inc. Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)			
+32.2	Certification of Executive Vice President and Chief Financial Officer of Reliant Resources, Inc. Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)			

EXHIBIT 12.1

RELIANT RESOURCES, INC. AND SUBSIDIARIES

RATIO OF EARNINGS FROM CONTINUING OPERATIONS TO FIXED CHARGES

	For The Year Ended December 31,				
	1999	2000	2001	2002	2003[1]
	(In Thousands, Except Ratio Amounts)				
Fixed charges:					
Interest expense	$ —	$ 7,019	$ 16,152	$266,962	$ 516,729
Interest expense — affiliated companies, net[2]	5,534	172,311	—	—	—
Capitalized interest	8,250	34,625	58,720	27,441	84,225
Interest within rent expense	479	10,818	35,174	54,407	66,556
Total fixed charges	$14,263	$224,773	$110,046	$348,810	$ 667,510
Earnings from continuing operations:					
Income (loss) from continuing operations before income taxes	$11,326	$245,880	$751,498	$229,312	$(822,075)
Loss (income) of equity investments of unconsolidated subsidiaries	793	(42,860)	(6,771)	(17,836)	1,652
Subtotal	12,119	203,020	744,727	211,476	(820,423)
Plus -					
Fixed charges from above	14,263	224,773	110,046	348,810	667,510
Amortization of capitalized interest	138	852	2,408	3,844	5,705
Distributed income of equity investees	—	17,929	27,159	2,975	4,400
Less -					
Capitalized interest	(8,250)	(34,625)	(58,720)	(27,441)	(84,225)
	$18,270	$411,949	$825,620	$539,664	$(227,033)
Ratio of earnings from continuing operations to fixed charges	1.28	1.83	7.50	1.55	—

(1) For 2003, our earnings were insufficient to cover our fixed charges by $895 million.

(2) If the net amount for the applicable period netted to interest income, it is excluded from this schedule for purposes of calculating fixed charges.

Exhibit 23.1

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in registration statements on Form S-3 (333-107295 and 333-107296) and Form S-8 (333-60124, 333-60328, 333-74754, 333-74790, 333-86608, 333-86610, 333-86612, 333-98273, 333-101471, 333-101473, 333-106097 and 333-106098) of Reliant Resources, Inc. of our:

Report dated March 5, 2004 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the change in method of accounting for asset retirement obligations, energy trading contracts, consolidation of variable interest entities, and the change in presentation of revenues and costs of sales associated with non-trading commodity derivative activities in 2003, the change in method of presenting trading activities from a gross basis to a net basis, and goodwill and other intangibles in 2002 and, accounting for derivatives and hedging activities in 2001), on the consolidated financial statements and related financial statement schedules of Reliant Resources, Inc. appearing in this Annual Report on Form 10-K of Reliant Resources, Inc. for the year ended December 31, 2003.

Report dated March 5, 2004 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the change in method of, accounting for asset retirement obligations, and the change in presentation of revenues and costs of sales associated with non-trading commodity derivative activities in 2003, goodwill and other intangibles in 2002, and derivatives and hedging activities in 2001), on the consolidated financial statements of Reliant Energy Mid-Atlantic Power Holdings, LLC appearing in this Annual Report on Form 10-K of Reliant Resources, Inc. for the year ended December 31, 2003.

Report dated March 5, 2004 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the change in method of, accounting for asset retirement obligations, and the change in presentation of revenues and costs of sales associated with non-trading commodity derivative activities in 2003, goodwill and other intangibles in 2002, and the application of procedures relating to certain disclosures and reclassifications related to the 2001 financial statements that were audited by other auditors who have ceased operations and for which Deloitte & Touche LLP have expressed no opinion or other form of assurance other than with respect to such disclosures and reclassifications) on the consolidated financial statements of Orion Power Holdings, Inc. as of December 31, 2002 and 2003 and for the periods from January 1, 2002 to February 19, 2002 and February 20, 2002 to December 31, 2002 and for the year ended December 31, 2003, appearing in this Annual Report on Form 10-K of Reliant Resources, Inc. for the year ended December 31, 2003.

Report dated March 5, 2004 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to, the change in accounting for energy trading contracts and its presentation of revenues and costs of sales associated with non-trading commodity derivative activities in 2003 and the change in method of accounting for goodwill and other intangibles, and the change in method of presenting trading activities from a gross basis to a net basis in 2002) on the consolidated financial statements of Reliant Energy Retail Holdings, LLC appearing in the this Annual Report on Form 10-K of Reliant Resources, Inc. for the year ended December 31, 2003.

DELOITTE & TOUCHE LLP

Houston, Texas
March 5, 2004