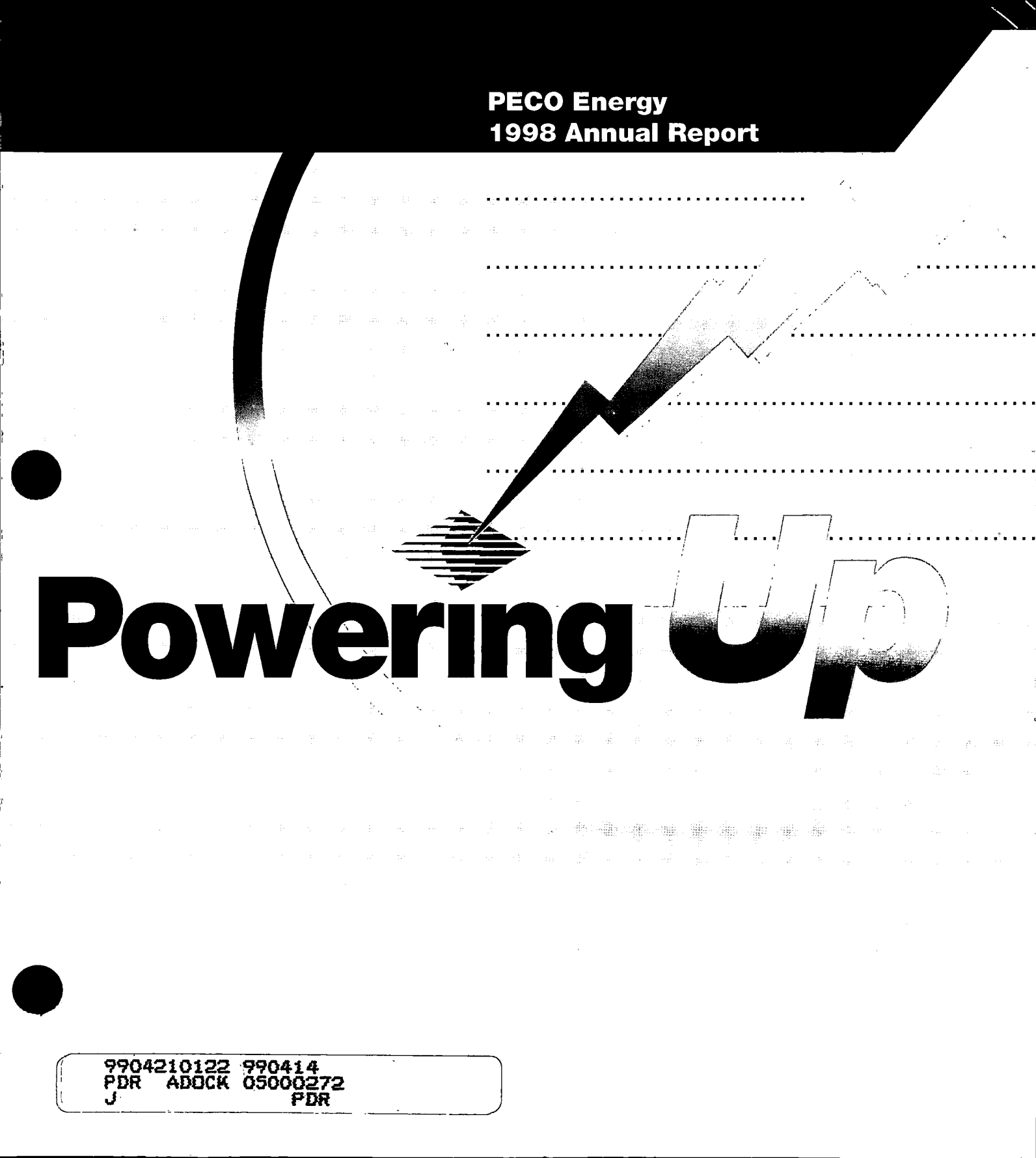
PECO Energy
1998 Annual Report



Powering Up

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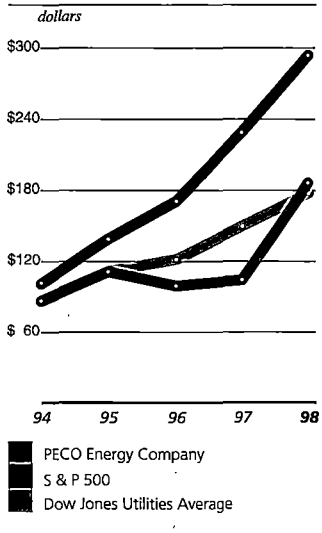
Comparison of 5 Year Cumulative Total Return

$100 invested on 12/31/93 in stock or index including reinvestment of dividends.



Financial Highlights

(Thousands of Dollars)	**1998**	1997	% Change
Operating Revenues	**$ 5,210,482**	$ 4,617,901	12.8%
Operating Expenses, excluding taxes	**$ 3,647,653**	$ 3,302,179	10.5%
Taxes Charged to Operations	**$ 599,169**	$ 602,860	(0.6%)
Operating Income	**$ 1,283,314**	$ 1,005,631	27.6%
Extraordinary Item (Net of taxes)	**$ (19,654)**	$(1,833,664)	98.9%
Earnings Applicable to Common Stock (After extraordinary item)	**$ 499,615**	$(1,513,910)	—
Earnings Applicable to Common Stock (Before extraordinary item)	**$ 519,269**	$ 319,754	62.4%
Earnings per Average Common Share (Dollars) (After extraordinary item)	**$ 2.24**	$ (6.80)	—
Cash Dividends Paid per Common Share (Dollars)	**$ 1.00**	$ 1.80	(44.4%)
Average Shares of Common Stock Outstanding (Thousands)	**223,219**	222,543	0.3%
Capital Expenditures	**$ 415,331**	$ 490,200	(15.3%)
Common Shareholders' Equity	**$ 3,057,342**	$ 2,726,731	12.1%
Book Value Per Average Common Share (Dollars)	**$ 13.61**	$ 12.25	11.1%

PECO Energy Company is a leader in generating and marketing electricity in competitive markets across the United States. Since 1929, we have provided retail electric and natural gas service to customers in southeastern Pennsylvania, serving more than 1.5 million customers in 1998. With the advent of deregulation, we have developed a wide range of competitive businesses that build upon a broad asset base, our market knowledge and our core capabilities. Our generation portfolio of more than 9,000 megawatts is among the most competitive in the United States. Our power marketing division, Power Team, is one of the leading real-time deliverers of wholesale electricity operating throughout the continental United States. Through our Exelon division, we provide a variety of unregulated energy and utility infrastructure services, including electric supply to business and residential customers across Pennsylvania and competitive wireless and fiber optics-based communications services.

While our performance in 1998 was impressive, we are still powering up. We are only just beginning to feel the positive impact of our renewed organization, vision and strategy. We are building our leadership position in deregulated markets by continuing to increase our powers of:

Performance	demonstrated by excellent financial and operating results in 1998	2
Vision	becoming the world's leading provider of clean energy	5
Boldness	aggressively growing a competitive generation portfolio	6
Experience	leading the industry in power marketing	8
Innovation	growing and developing new ventures	10
Alignment	linking our people and performance to shareholder interests	12

Powering Up

We will continue to tap these business powers to create value for our shareholders and customers that no other energy company can equal.

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To My Fellow Shareholders:
What a difference a year makes! When I wrote my letter to you a year ago, our company was in one of its greatest periods of uncertainty. We were facing what could have been a protracted legal challenge to an unfavorable regulatory order; Wall Street's confidence in our competitive future was weakened, and our financial results for 1997 were most disappointing. Today, that picture has dramatically changed for the better, and I am proud to report to you that 1998 was a year of powerful performance for PECO Energy.

Among our most significant accomplishments in 1998:

- Earnings per share were $2.66 before special items, an increase of 46% over 1997 performance.
- PECO Energy's common stock delivered a total annual return of 78%.
- We negotiated a fair and balanced electric deregulation plan.
- Our power marketing group, Power Team, increased sales volume 13%.
- Our unregulated energy supply business, Exelon Energy, became the most successful player in the new Pennsylvania Electric Choice program.
- AmerGen, our joint venture with British Energy, successfully negotiated the first-ever U.S. purchase of a nuclear generating station, scheduled for completion this year.
- PECO Energy was named "Energy Company of the Year" by the Washington International Energy Group.

Strong Financial Results
Earnings per share in 1998, before special items, were $2.66. That represents a 46% increase over 1997 earnings from operations. After accounting for an extraordinary charge related to the redemption of higher cost debt and a year-end adjustment for the cost of our on-going workforce reduction program, earnings were $2.24 per share. Our power marketing activities contributed significantly to our strong earnings performance, particularly in the third quarter when we achieved the highest quarterly earnings in our company's history. During 1998, we also benefited from lower operating and maintenance expenses, significantly lower fuel and replacement power costs following the Salem Nuclear Generating Station's full return to service in early 1998, and a lower effective income tax rate.

PECO Energy Delivered Excellent Returns in 1998
PECO Energy's shares of common stock closed 1998 at $41.75, a 74% increase over the 1997 close of $24 per share. The unprecedented increase in our common stock price, combined with dividends paid, resulted in a total return to our shareholders of 78%, winning PECO Energy the number one spot in the rankings for total shareholder return among the 25 largest U.S. electric utilities. The catalysts to our dramatically improved valuation were the favorable completion of our long and difficult regulatory restructuring proceeding and the progress we have made in executing our competitive growth strategy.

Favorable Restructuring Plan in Place
The most significant event of 1998 was the successful completion of our restructuring proceeding before the Pennsylvania Public Utility Commission (PUC). In May, the PUC approved a fair and balanced plan that on January 1, 1999 opened our electric generation business to competition. The plan provides our customers with guaranteed savings through across-the-board rate cuts for the next two years as well as the freedom to choose their energy supplier. PECO Energy will continue to provide regulated distribution services to all customers in our traditional service territory.

For PECO Energy, the restructuring plan provides a very reasonable transition to retail competition while maintaining a solid financial foundation upon which we're building new, competitive businesses. A central element of the plan is the allowed recovery of almost $5.3 billion in

rmance

stranded investments. On January 1, 1999, we began recovering these investments from our customers through a special transition charge that will remain in place for 12 years, while earning a 10.75% return on the balance. The plan also gives us the ability to securitize the majority of our recoverable stranded costs through the issuance of up to $4 billion of "transition bonds." The issuance of these highly rated bonds will enable us to significantly realign our capital structure, most notably through the retirement of debt and preferred stock, and the repurchase of common stock.

Our Vision for the Future

Our business and industry are clearly moving into a vastly different and exciting era. Given the speed of this change, we think it is essential to have a clear picture of where we're going, and the kind of company we want to be when we get there. In 1998, we developed a powerful new corporate vision — To become the world's leading provider of clean energy. (Our complete vision and mission statements are presented on page 5 of this report.) This mission will guide and propel our progress for years to come, and we are continuing to build the processes and structures to make it a reality.

Pursuing Aggressive Growth Objectives

To mark our progress in achieving our long-term vision for the Company, in 1998 we established the following goals that we will work to meet by the year 2003:

- To retain a 75% market share in our traditional service territory, achieved through customer retention by our local distribution company, PECO Energy Distribution, as well as market share growth by Exelon Energy.
- To nearly triple our electric generation capabilities to 25 gigawatts through acquisitions and long-term supply agreements by the year 2003.
- To achieve a 50% increase in our earnings per share between 1998 and 2003.

To achieve these aggressive earnings and growth objectives, we will build upon our strengths in power generation and power marketing. We will also continue to develop ventures that leverage our core business capabilities, and continuously work to optimize the cost efficiency of PECO Energy Distribution Company.

Corbin A. McNeill, Jr.,
PECO Energy Chairman, President and Chief Executive Officer

Building a Competitive Retail Market Share

Our long-term goal is to maintain a very strong market share in our traditional electric service area, plus establish a significant position in other electric retail markets across Pennsylvania, and ultimately other regions of the United States. As of January 2, 1999, two-thirds of Pennsylvania's electric customers gained the ability to choose their energy suppliers. In anticipation of the opening of retail markets, Exelon Energy conducted a marketing cam-

paign in 1998 that has helped it gain more than 130,000 retail customers. To date, Exelon Energy has established the largest competitive market share in the state and is one of the few suppliers with customers in all of Pennsylvania's electric franchise areas.

Even with the new opportunities for choice that our customers have, I am pleased to note that a large number of our customers have opted not to switch their energy supplier and have remained with PECO Energy Distribution. I believe this loyalty is a testament to our strong ties to the communities we serve as well as our proud history of service excellence.

Increasing PECO's Generation Capabilities

We took the first important step in expanding our generation portfolio in July of 1998, when we entered into an agreement to purchase Unit 1 of Three Mile Island Nuclear Generating Station (TMI) from GPU, Inc. We will purchase the unit through AmerGen, our joint venture with British Energy, and expect to complete the transaction by mid-1999. TMI Unit 1 has one of the finest operational and safety records in the industry. We see real opportunities for even stronger performance by applying the same spirit of innovation and operational excellence that has earned our Peach Bottom and Limerick nuclear stations world-class status in performance, safety and cost efficiency. Based on our latest estimates, we believe the TMI Unit 1 acquisition will make a positive contribution to earnings in its first year.

The growth of our generating capacity will go hand-in-hand with the growth of Power Team's wholesale energy marketing operations. Power Team has developed the expertise, market knowledge and a portfolio management strategy that consistently produce superior value for PECO Energy. In 1998, Power Team delivered 100% of the power it contracted to provide. This deliverability record was particularly impressive given the supply problems experienced by other marketers during last summer's shortages in the Midwest.

Managing our Businesses to Achieve Excellence

Now more than ever, we need a talented and motivated workforce to help us accomplish the goals we have set. We are fulfilling that need by building an employee team which is smart, ambitious and motivated to succeed. Over the past year, we have added significantly to our talent base and have recruited leaders from a variety of competitive industries, such as oil, gas and chemicals.

I believe in challenging our workforce, providing the right incentives to achieve our goals and then rewarding excellent results. In 1998 we put in place a new incentive compensation system that includes stock option grants for every employee, which vest only after our stock price meets aggressive price targets. We also began offering quarterly cash bonuses to employees when their respective business units meet value-driven business and operational objectives. Under this new system, employees and management will only enjoy financial rewards when we create value for our shareholders.

New Corporate Structure Proposed

In 1999, we will be asking common shareholders to vote on a proposal to create a holding company structure for PECO Energy that, if approved, will establish a new corporate holding company named PECO Energy Corporation. This will be the first step in establishing separate subsidiaries organized around our three key lines of business: power generation and marketing, gas & electric distribution and unregulated energy service-related businesses. We believe that this proposed structure will give us the flexibility to compete in new markets and grow our businesses as new opportunities arise.

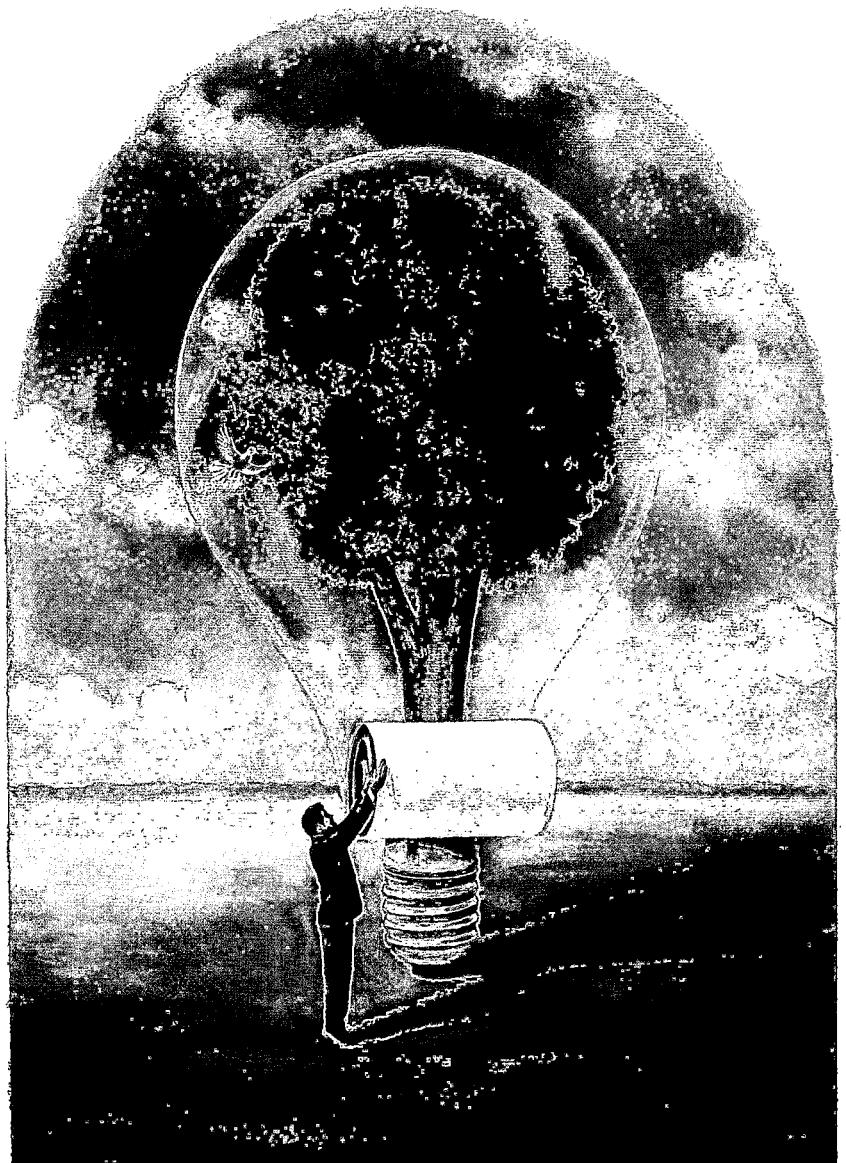
Before closing, I want to recognize and thank fellow board member Admiral Kinnaird R. McKee, who stepped down from our Board of Directors in 1998 after completing 10 years of service. I would also like to welcome Rosemarie Greco, who joined our board in 1998. And finally, I want to thank you, our shareholders, for your continued support and confidence. All of us who are a part of PECO Energy are excited about building on our competitive strengths in the coming year and beyond.

Corbin A. McNeill, Jr.
PECO Energy Chairman, President and Chief Executive Officer
February 5, 1999

Vision

Becoming the world's leading provider of clean energy.

In 1998, we developed a powerful vision statement — to become the world's leading provider of clean energy. This vision is guiding and propelling our strategy, our actions and ultimately our success.



- We are an energy company that measures our success by our impact on the lives of others.
- We will provide energy safely, reliably and affordably to power the 21st century dreams of families and businesses.
- We will create value for our shareholders and our customers that no other energy company can equal.
- We will ensure that air and water are cleaner for generations to come.
- We will be a company respected as much for what we value as for the value we create.

The power of Bold

Our key for success in deregulated power generation markets will be to own or control a significant amount of environmentally clean and efficient generating capacity in targeted regions of the United States. As part of our vision to become the world's leading provider of clean energy, we set a goal of increasing our generation capacity from just over 9,000 megawatts to 25,000 megawatts in the next five years.

We are working to achieve this goal through an aggressive yet disciplined acquisition program, and through securing long-term supply contracts with generation asset owners.

Under our acquisition program, we are targeting attractively priced, environmentally and operationally sound plants that have the potential for outstanding performance and strong returns. As we make acquisitions, we will work to develop regional groups of geographically synergistic plants that allow us to leverage our resources and expertise in specific geographic areas.

In 1998, we began expanding our Mid-Atlantic operating group, consisting of the four nuclear units we operate at Limerick and Peach Bottom stations. In October, we reached a

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We are pursuing a bold national strategy designed to nearly triple our generating capacity within five years and strengthen our market presence throughout the United States.

final agreement to purchase Unit 1 at GPU's Three Mile Island Nuclear Generating Station through AmerGen, our joint venture with British Energy. TMI Unit 1, with its strong operating record and 786 megawatts of nuclear baseload capacity, will be an excellent addition to our generating portfolio. This plant has twice set world records for continuous days of operation. AmerGen is obtaining all necessary governmental approvals and expects to complete this transaction by mid-1999.

Building Our Portfolio of High Performers

PECO is building its portfolio by targeting generating plants with potential for high capacity factors and low operating costs, and will use its operating strengths to improve performance of acquired plants.

Leveraging Our Operational Excellence

Good acquisitions are not enough. It is what we do with the plants after they are acquired that determines their true value. The second pillar of our generation strategy is our proven operating expertise. Our Limerick and Peach Bottom nuclear stations are among the safest and best-performing nuclear plants in the industry. These facilities have some of the highest capacity factors and lowest production costs in the nation. We are targeting additional plants with similar high performance potential.

In 1999, we plan to continue to expand our generation portfolio through a strategy that focuses first and foremost on building earnings potential and strong investment returns. We will seek out the best possible plants at competitive prices, working to create a balanced portfolio of generation assets, including nuclear, hydroelectric and clean-burning fossil fuel plants. This strategy positions us to be a leader in power generation in North America and achieve our bold aspiration of becoming the world's leading provider of clean energy.

The Exp

A pioneer in the industry, PECO's Power Team continues to demonstrate its leadership in marketing and delivering wholesale power throughout the United States.

The expertise of our power marketing group, Power Team, was again proven in 1998 with a record of 100% delivery in highly competitive and rapidly changing U.S. power markets. Power Team continues to use its expertise to expand its assets and markets in the United States and Canada and increase its contributions to our bottom line. At the same time, our strategy of growing our generation portfolio will provide Power Team with additional sources of low-cost power.

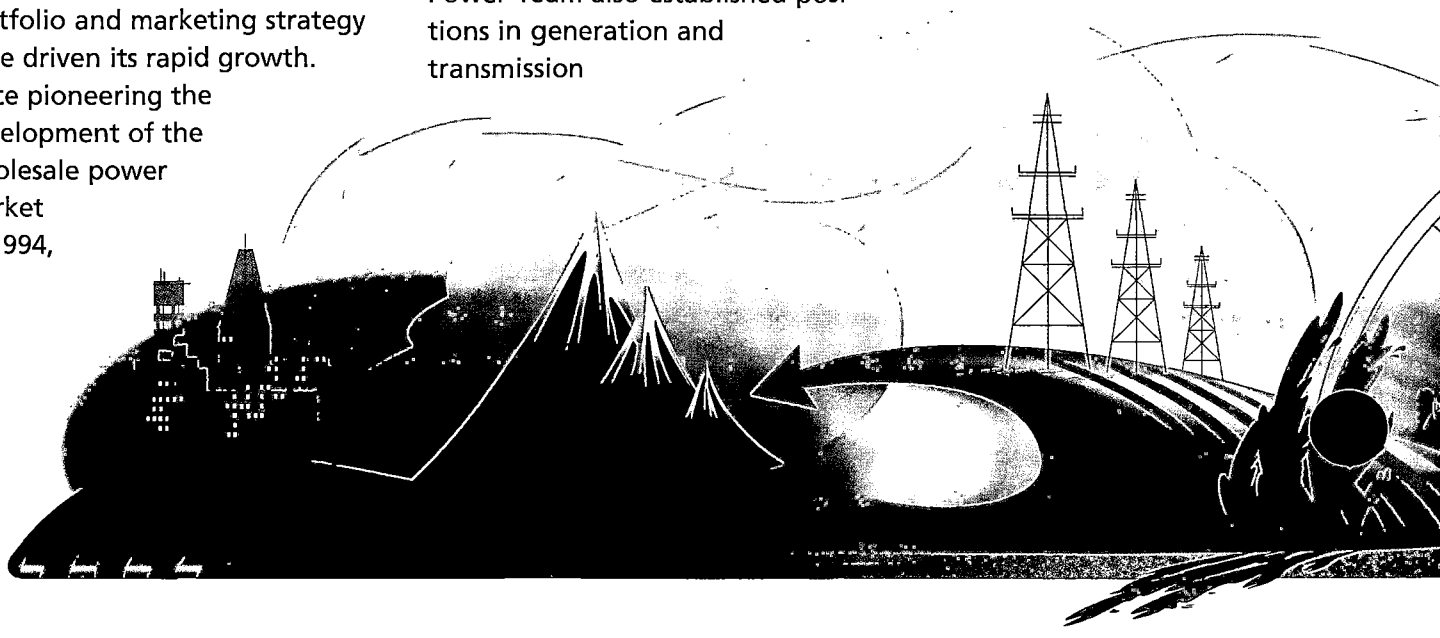
The Value of Experience

Power Team's knowledge, supply portfolio and marketing strategy have driven its rapid growth. Since pioneering the development of the wholesale power market in 1994, Power Team has nearly tripled its sales to become one of the largest "real time" deliverers of wholesale electricity in the continental United States. Today, Power Team's customer base includes municipal utilities, investor-owned utilities, rural cooperatives and marketers.

Power Team's most significant competitive advantage is a diverse portfolio of generation assets, including both PECO-generated power and a variety of long-term and short-term power purchase contracts with other suppliers. As an early player, Power Team also established positions in generation and transmission assets across the United States that have become more valuable as competition has increased. These assets give Power Team the flexibility to move power quickly to areas where demand is strongest.

Expanding Power Sources and Markets

In 1998, Power Team continued to diversify its power sources and markets. Power Team expanded its supply portfolio by adding generating sources outside of PECO Energy's traditional service territory. PECO-generated power accounted for only about a



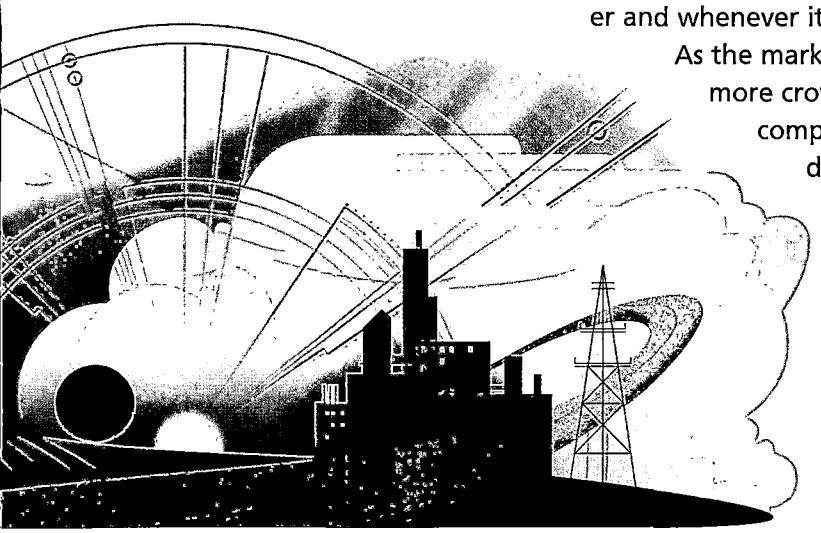
erience

quarter of our total supply portfolio and Power Team continues to add new capacity. For example, through a partnership with Tenaska, Inc., Power Team will market the output of a new 800-megawatt plant, which will be the largest merchant power plant in the United States when it opens in 2000.

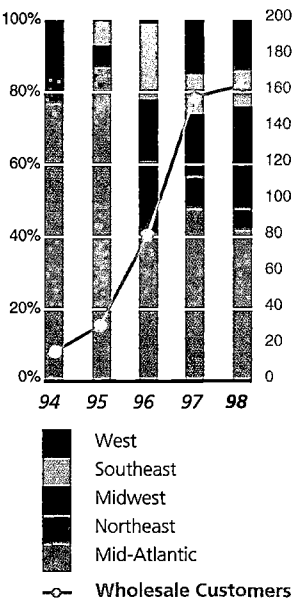
Drawing upon our broad supply portfolio, Power Team also expanded the size and scope of sales across the United States. For the first time, Power Team sold more power outside PECO's traditional Mid-Atlantic service territory than inside (see chart).

To respond to the more complex needs of customers in deregulated markets, Power Team has created innovative solutions for customers. For example, we developed products that enable us to serve entire municipalities in Pennsylvania and Maine. In addition, Power Team has developed arrangements that allow us to support our hydro-based customers in periods of low hydropower generation. With a marketing operation that runs 24 hours per day, 7 days per week, our national transmission access and our unique and innovative delivery knowledge, we can provide power just about wherever and whenever it is needed.

As the market becomes more crowded and competitive, our demonstrated experience will become more valuable. We are well positioned to take advantage of emerging opportunities in retail markets as they open to competition across the country and as we add low-cost, strategically located supply to our portfolio.



Power Team's Growing Geographic Reach and Wholesale Customers



For the first time, Power Team sold more power outside the Mid-Atlantic region than inside as we continued to grow our wholesale market.

The power of innovation

Under the umbrella brand of Exelon, we are developing diverse businesses that leverage our assets and skills in high-potential markets.

In 1998, we increased our power of innovation by developing and expanding several new businesses, brought together under the umbrella brand of Exelon. These ventures, which leverage our core competencies into new areas, have high potential for future growth. Among our early achievements we have: established ourselves as the most successful electric generation supplier in Pennsylvania's Electric Choice program; signed up over 100,000 wireless phone customers; installed a telecommunications network consisting of over 27,000 fiber miles; and began to prove the viability of a new infrastructure services business.

Leveraging Our Strengths

This year, we leveraged our core strengths in operations and utility infrastructure to launch or expand several new ventures:

- **Energy:**
  Exelon Energy provides competitively priced electricity and natural gas to residential, commercial and industrial clients in deregulated retail energy markets. Exelon has been successful in meeting the initial challenge of competition, becoming the largest electric generation supplier in Pennsylvania's Electric Choice program — building market share not only in our traditional service area but also in every distribution area of the state. The strong systems we developed in 1998 for customer acquisition, customer care, energy supply and billing ensure we are well positioned for the expanded choice program in 1999. With the unique experience we've gained in Pennsylvania, we are poised to move quickly into any U.S. market where regulatory conditions provide open retail competition.
- **Communications:**
  Exelon Communications is working with experienced partners to develop wireless phone networks and local fiber optics communications services in the Philadelphia region. In its first full year, Exelon's joint venture with AT&T Wireless has become a significant competitor in the region's wireless telecommunications business. Our transmission infrastructure and skilled staff have allowed us to build wireless cell sites rapidly and efficiently, by utilizing existing assets. We developed innovative approaches to piggyback antennas and cell sites on top of electrical transmission poles and towers. In the first year, the joint venture built a base of over 100,000 subscribers, well above our target, and established a significant network in the Philadelphia area. We are well prepared to pursue the estimated two million new customers expected to sign up for wireless service in the region in the next five years. In partnership with Hyperion Communications, a leading provider of competitive communications services, we also installed 27,000 fiber miles in the PECO service territory as well as Allentown, Bethlehem, Easton and Reading. This venture redeploys our strengths in building and maintaining our current power delivery network to establish a new communications platform.

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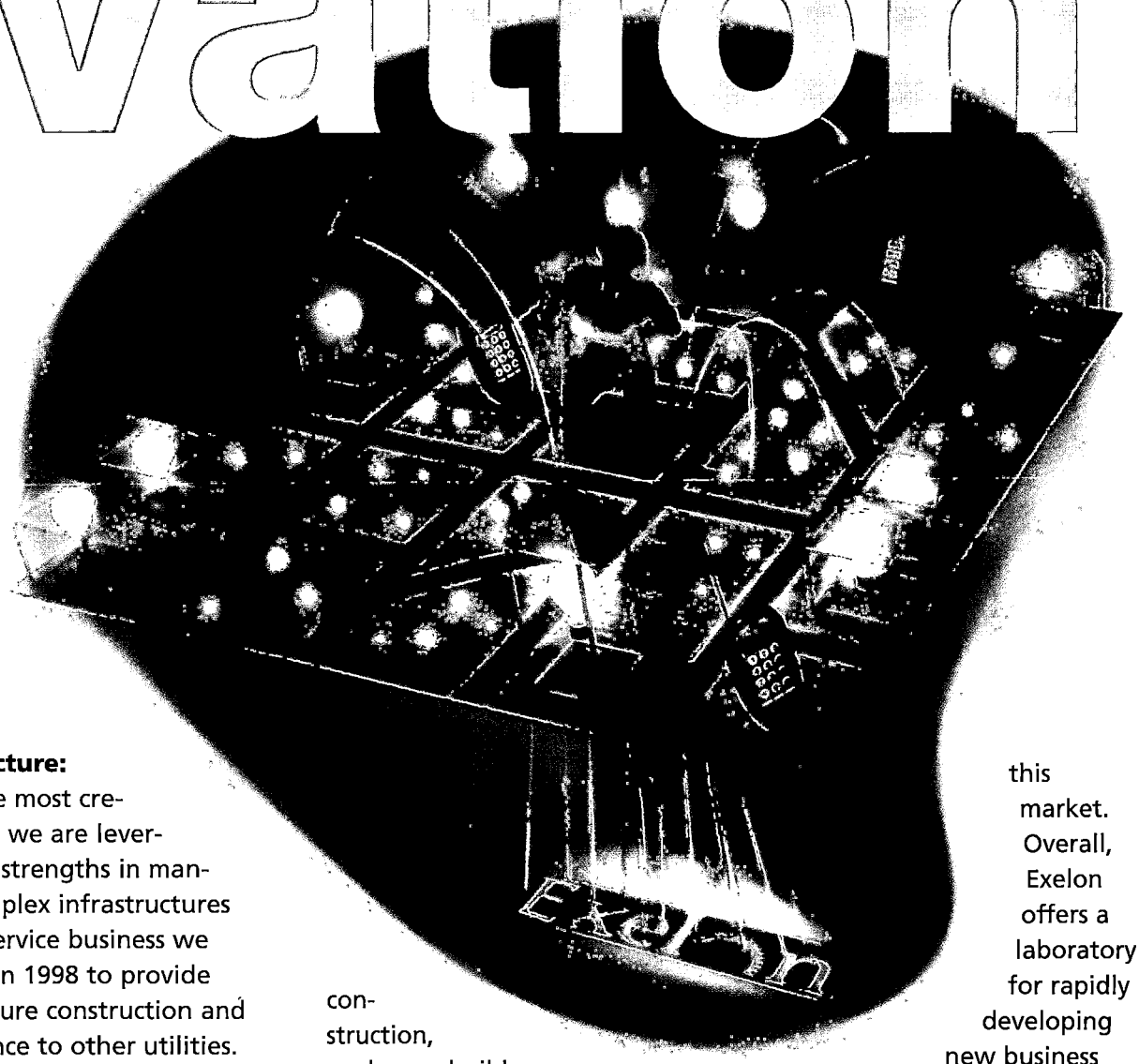

- **Infrastructure:** One of the most creative ways we are leveraging our strengths in managing complex infrastructures is a new service business we launched in 1998 to provide infrastructure construction and maintenance to other utilities. In new residential construction, for example, electric, gas, telephone and cable companies traditionally use separate service technicians to install their lines. We are developing a venture to provide single-source service. By combining installation of electric, gas, telephone and cable, Exelon Infrastructure Services reduced total costs by a third in installing service to more than 8,000 homes in 1998. In addition to new construction, we began building a utility infrastructure maintenance business, including contracts to maintain street lighting in Philadelphia, provide design services in southern New Jersey and assess utility maintenance operations at a midwestern utility. As utilities face pressures to cut costs, they will find it increasingly attractive to outsource many construction and maintenance functions. We are well positioned to continue to grow this market. Overall, Exelon offers a laboratory for rapidly developing new business ideas, allowing us to take advantage of fast-moving opportunities. Exelon is developing a wide range of other seed projects and pilot programs with high future growth potential. The flow of innovative projects in the pipeline and strong early results are signs of the potential contributions of the power of innovation to our future progress and shareholder value.

The power of Alig

We have refocused our performance measures and compensation systems to align our organization around aggressive goals designed to enhance shareholder value.

Building Upon a Solid Foundation

Our local distribution company, PECO Energy Distribution (PED), provides a strong foundation of earnings, cash flow and core expertise to support our other non-regulated growth initiatives. In 1998, we reorganized PED to ensure we are positioned for competition and to increase alignment with shareholder interests. The changes in PED were the centerpiece of a company-wide shift in performance measures, management systems and incentives to increase alignment and ownership.

With our rates for delivering energy capped by regulators through mid-2005, our greatest opportunity for optimizing the earnings contribution of PED comes from reducing our operating costs while sustaining high performance and service. We began driving down our cost of delivery in 1998, with a goal of reducing costs by nearly 20% by 2000.

To achieve this goal, we restructured PED to focus on financial performance, market share, cost containment and increasing service levels to optimize customer satisfaction and retention. By the end of 2000, we expect to reduce our 1998 PED staff by more than 20%.

These actions are part of an overall corporate initiative to increase performance and alignment. We conducted a Cost Competitiveness Review that identified potential annual cost savings of $150 million across the entire corporation, which we are actively working to realize. Our goal in making these reductions is not only to decrease operating costs, but to do so while continuing to improve customer-related performance through improved processes.

Promoting a Performance Ethic

In 1998, we began to implement one of the most rigorous performance-based compensation and management systems in the industry. It provides opportunities for stock ownership at all levels of the organization through stock option grants that vest only when performance goals are met. It is designed to promote a performance ethic throughout the organization and align employees' interests directly with the interests of shareholders.

We embedded our vision and objectives in a coordinated system of goals, organization, performance feedback and consequence management. In 1998, we began implementing a new system of incentives based upon corporate and business unit performance that will be applied across all levels of the organization. We shifted more compensation from base pay to performance-based pay. A new incentive plan in our nuclear division, for example, has tied compensation to safety and

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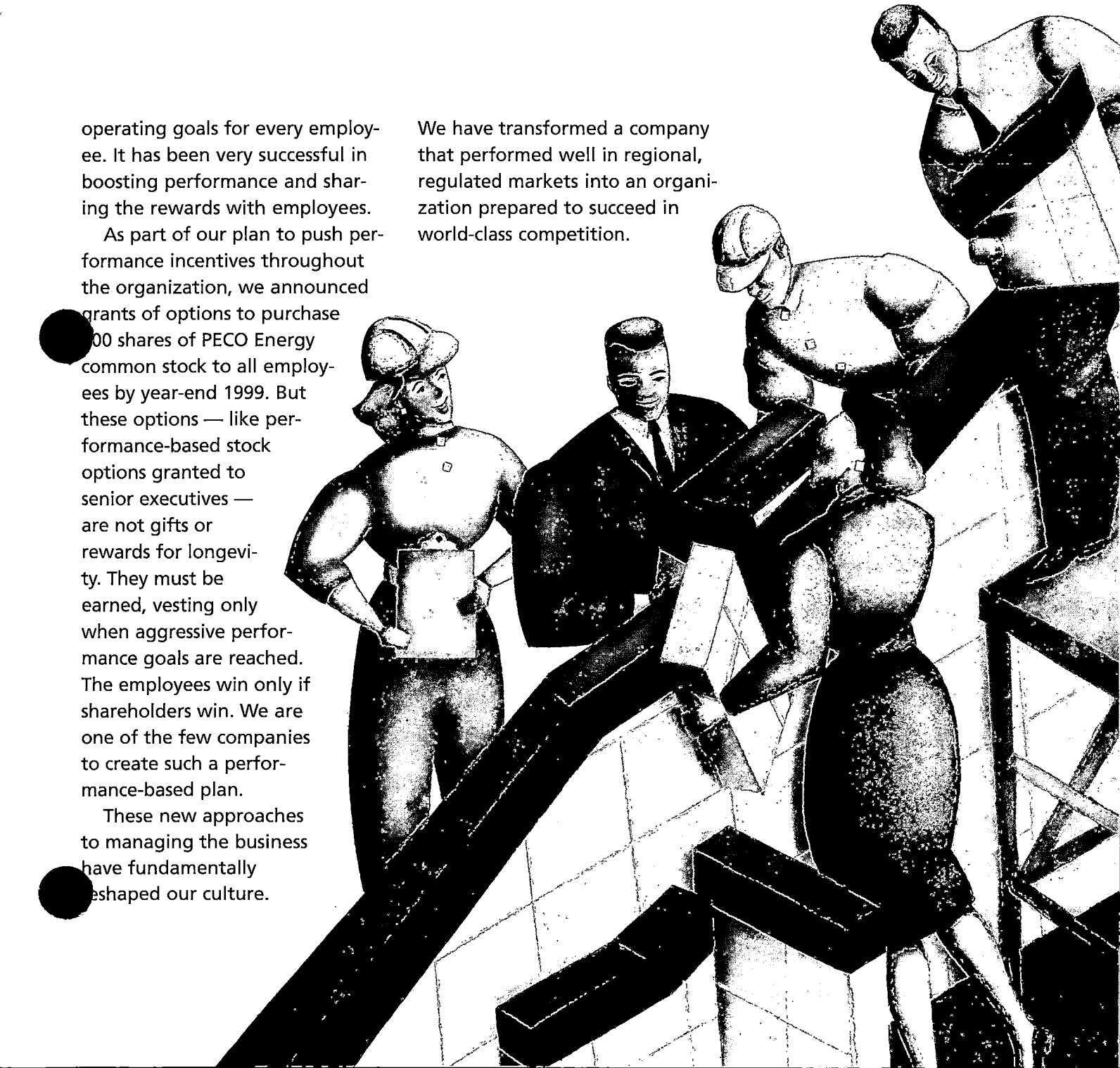
operating goals for every employee. It has been very successful in boosting performance and sharing the rewards with employees.

As part of our plan to push performance incentives throughout the organization, we announced grants of options to purchase 00 shares of PECO Energy common stock to all employees by year-end 1999. But these options — like performance-based stock options granted to senior executives — are not gifts or rewards for longevity. They must be earned, vesting only when aggressive performance goals are reached. The employees win only if shareholders win. We are one of the few companies to create such a performance-based plan.

These new approaches to managing the business have fundamentally eshaped our culture.

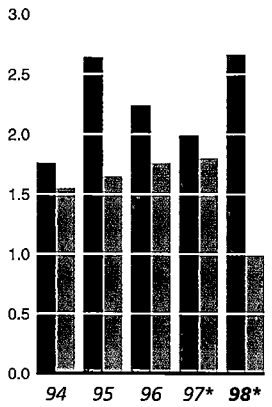
We have transformed a company that performed well in regional, regulated markets into an organization prepared to succeed in world-class competition.



Performance

Earnings* and Dividends

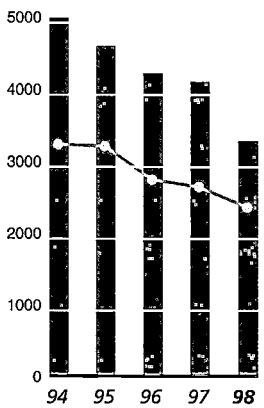
dollars per share



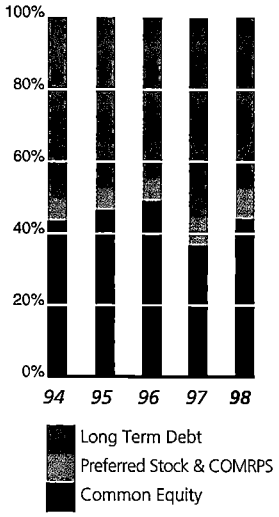
**Before extraordinary item and special charges*

Total Debt and Interest Charges

millions of dollars

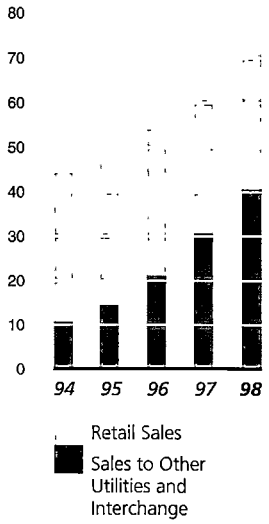


Capitalization



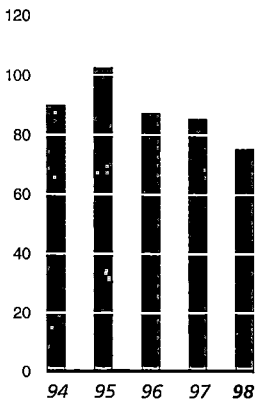
Total Electric Sales

billions of kilowatthours



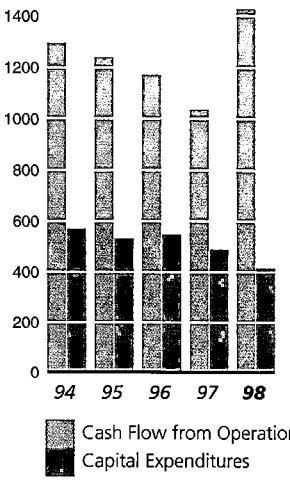
Gas Sales and Transported Gas

billions of cubic feet



Cash Flow from Operations and Capital Expenditures

millions of dollars



Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The Electricity Generation Customer Choice and Competition Act (Competition Act), enacted in December 1996, provided for the restructuring of the electric utility industry in Pennsylvania, including the institution of retail competition for generation supply beginning in 1999. Pursuant to the Competition Act, in April 1997, the Company filed with the Pennsylvania Public Utility Commission (PUC) a restructuring plan in which it identified $7.5 billion of retail electric generation-related stranded costs.

At December 31, 1997, the Company determined that its electric generation business no longer met the criteria of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." In connection with the discontinuance of SFAS No. 71, the Company performed a market value analysis of its generation assets and wrote-off $1.8 billion (net of income taxes) of unrecoverable electric plant costs and regulatory assets. See Note 4 of Notes to Consolidated Financial Statements.

In May 1998, the PUC entered an Opinion and Order (Final Restructuring Order) approving a joint petition and settlement of the Company's restructuring case. Under the Final Restructuring Order, the Company has received approval to recover stranded costs of $5.26 billion over 12 years beginning January 1, 1999 with a return of 10.75%. The Final Restructuring Order provides for the phase-in of customer choice of electric generation suppliers (EGS) for all customers: One-third of the peak load of each customer class on January 1, 1999; one-third on January 2, 1999; and the remainder on January 2, 2000. The Final Restructuring Order calls for an across the board retail electric rate reduction of 8% in 1999. This rate reduction will decrease to 6% in 2000. See Note 3 of Notes to Consolidated Financial Statements.

Based on the estimated annual sales of the Company in the Final Restructuring Order, the rate reductions are expected to reduce the Company's revenues from retail electric sales by $270 million in 1999 and $200 million in 2000. The Company believes that its revenues from retail electric sales will be further reduced by competition for electric generation services within its traditional service territory. The Company is actively participating in the competitive electric generation supply market throughout Pennsylvania. In addition, the Company anticipates lower depreciation and amortization expense in 1999 as a result of the amortization schedule for the Company's stranded cost recovery.

In light of the expected impact on future revenues of the Final Restructuring Order and competition for electric generation services, the Company is continuing its cost management efforts through a Cost Competitiveness Review (CCR). The goal of CCR is to achieve significant cost savings while maintaining high levels of service quality, reliability, safety and overall performance. The cost-control targets of CCR include reducing annual operating and maintenance expense by at least $150 million by 2001. The expense reductions will be realized, in part, through the elimination of approximately 1,200 employee positions. As part of the CCR, in April 1998, the Board of Directors authorized the implementation of a retirement incentive program and an enhanced severance benefit program to accompany targeted workforce reductions. In the fourth quarter of 1998, the Company incurred an after-tax charge to earnings of $74 million to recognize costs related to the CCR workforce reduction.

Discussion of Operating Results

Earnings

The Company recorded basic earnings per average common share of $2.24 in 1998 as compared with a loss of $6.80 per share in 1997 and earnings per share of $2.24 in 1996. Earnings per share in 1998 reflect higher revenues net of fuel of $0.14 per share primarily attributable to sales to other utilities and interchange sales; lower operating and maintenance expenses of $0.10 per share and lower fuel expenses of $0.22 per share as a result of the full return to service of Salem Nuclear Generating Station (Salem); and lower operating and maintenance expenses of $0.21 per share. In addition, earnings include the effects of a lower effective income tax rate of $0.34 per share. These increases were partially offset by higher depreciation and amortization expense of $0.17 per share; a charge of $0.33 per share related to the CCR workforce reduction program initiated in 1998; and an extraordinary charge of $0.09 per share for premiums paid in connection with the redemption of higher cost long-term debt.

The loss in 1997 of $6.80 per common share was primarily due to an extraordinary charge of $8.24 per share reflecting the effects of the PUC Restructuring Order and deregulation of the Company's electric generation operations. 1997 earnings were also reduced by several one-time charges totaling $0.56 per share for changes in employee benefits, write-offs of information systems development charges reflecting clarification of accounting guidelines and additional reserves, including those for environmental site remediation; by $0.30 per share for higher depreciation expense resulting from a full year's increase in depreciation and amortization of assets associated with Limerick Generating Station (Limerick) and other assets; by $0.12 per share for income tax adjustments; by $0.09 per share for losses from new non-utility ventures; and by $0.05 per share for increased depreciation expense due to plant additions. These decreases were partially offset by a one-time $0.18 per share credit relating to the settlement of litigation arising from the outage of Salem; $0.08 per share for operational efficiencies; and higher revenues net of fuel of $0.06 per share primarily due to increased sales to other utilities.

Significant Operating Items

Revenue and Expense Items as a Percentage of Total Operating Revenues				Percentage Dollar Changes	
1998	**1997**	**1996**		**1998-1997**	**1997-1996**
92%	90%	90%	Electric	15%	8%
8%	10%	10%	Gas	(11%)	5%
100%	**100%**	**100%**	**Total Operating Revenues**	**13%**	**8%**
34%	28%	23%	Fuel and Energy Interchange	36%	33%
24%	31%	30%	Operating and Maintenance [a]	(12%)	12%
12%	12%	11%	Depreciation and Amortization	11%	19%
5%	7%	7%	Taxes Other Than Income	(10%)	4%
75%	**78%**	**71%**	**Total Operating Expenses**	**9%**	**19%**
25%	**22%**	**29%**	**Operating Income**	**28%**	**(19%)**
(7%)	(9%)	(10%)	Interest Expense	(10%)	(2%)
(9%)	(8%)	(9%)	Total Other Income and Deductions	(15%)	4%
16%	14%	20%	Income Before Taxes and Extraordinary Item	35%	(27%)
6%	6%	8%	Income Taxes	9%	(14%)
10%	8%	12%	Income Before Extraordinary Item	58%	(35%)

[a] Includes Early Retirement and Separation Programs Expense in 1998.

Operating Revenues

Total operating revenues increased in 1998 by $593 million to $5,210 million. This represented a $644 million increase in electric revenues and a $51 million decrease in gas revenues compared to 1997. Electric revenues increased as a result of additional sales to other utilities and interchange sales, in addition to higher wholesale prices. The decrease in gas revenues was primarily attributable to lower sales to house heating, small commercial and residential customers as a result of milder weather conditions in 1998, partially offset by higher purchased gas clause revenues charged in 1998 compared to 1997.

Total operating revenues increased in 1997 by $334 million to $4,618 million. This represented a $312 million increase in electric revenues and a $22 million increase in gas revenues over 1996. The increase in electric revenues was primarily due to increased sales to other utilities. The increase in gas revenues was primarily due to higher revenues from sales to commercial, house heating and residential customers resulting from higher purchased gas clause revenues charged in 1997 compared to 1996, partially offset by lower sales resulting from milder weather conditions in 1997. This increase was partially offset by reduced sales to interruptible customers switching to transportation service.

Increases/(decreases) in electric sales and revenues by class of customer for 1998 compared to 1997 and 1997 compared to 1996 are set forth as follows:

	1998 - 1997		1997 - 1996	
	Electric Sales	**Electric Revenues**	**Electric Sales**	**Electric Revenues**
	(Millions of kWh)	*(Millions of $)*	*(Millions of kWh)*	*(Millions of $)*
Residential	356	$ 30	(48)	$ (1)
House Heating	(140)	(10)	(217)	(12)
Small Commercial and Industrial	203	5	194	30
Large Commercial and Industrial	644	(11)	(174)	(21)
Other	(38)	2	(61)	8
Unbilled	61	(18)	397	45
Service Territory	**1,086**	**(2)**	**91**	**49**
Interchange Sales	1,556	152	992	33
Sales to Other Utilities	8,365	494	8,650	230
Total	**11,007**	**$ 644**	**9,733**	**$ 312**

Fuel and Energy Interchange Expense

Fuel and energy interchange expense increased in 1998 by $462 million to $1,752 million. The increase was primarily due to increased energy purchases associated with increased sales to other utilities and interchange sales partially offset by reduced replacement power expense related to Salem. Increases in purchases of non-utility generation also contributed to increased fuel expense in 1998. Fuel and energy interchange expense as a percentage of operating revenues, increased from 28% to 34% principally as a result of energy purchases associated with increased sales to other utilities and interchange sales.

Fuel and energy interchange expense increased in 1997 by $318 million to $1,290 million. The increase was primarily due to purchases associated with increased sales to other

utilities and a one-time billing credit in 1996 from a non-utility generator. Fuel and energy interchange expense as a percentage of operating revenues increased from 23% to 28% principally due to purchases associated with increased sales to other utilities.

Operating and Maintenance Expense

Operating and maintenance expense, inclusive of expenses associated with early retirement and separation programs, decreased in 1998 by $178 million to $1,253 million. The decrease in 1998 was primarily attributable to the full return to service of Salem which resulted in lower restart expenses, a credit to pension and benefits expense related to the performance of pension plan investments and lower property insurance and workers compensation insurance. These decreases were partially offset by the charge associated with the CCR workforce reduction program and increased power marketing expenses.

Operating and maintenance expense increased in 1997 by $157 million to $1,431 million primarily due to several one-time charges totaling $187 million, including charges for changes in employee benefits, write-offs of information systems development charges reflecting clarification of accounting guidelines and additional reserves, including reserves for environmental site remediation. These increases were partially offset by lower operating costs at Company-operated nuclear generating stations and lower administrative and general expenses resulting from the Company's ongoing cost-control efforts.

Depreciation and Amortization Expense

Depreciation and amortization expense increased in 1998 by $62 million to $643 million. The increase was primarily due to the amortization of Deferred Generation Costs Recoverable in Current Rates during 1998, preceding the Company's transition to market-based pricing of electric generation in 1999. Included in this amortization were charges that were included in operating and maintenance expense and interest expense in 1997.

Depreciation and amortization expense increased in 1997 by $92 million to $581 million. The increase was primarily due to increased depreciation of assets associated with Limerick which became effective October 1, 1996. Depreciation and amortization expense also increased due to additions to plant in service.

Interest Charges

Interest charges consist of interest expense, distributions on Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership (COMRPS) and Allowance for Funds Used During Construction (AFUDC). Interest charges decreased in 1998 by $22 million to $358 million. The decrease was primarily due to the Company's program to reduce and/or refinance higher cost, long-term debt, lower variable interest rates and the discontinuance of amortization of the loss on reacquired debt related to electric generation operations as of December 31, 1997. These decreases were partially offset by lower AFUDC and capitalized interest resulting from fewer projects in the construction base in 1998 and the replacement of $62 million of preferred stock with COMRPS in the third quarter of 1997.

Interest charges decreased in 1997 by $9 million to $380 million. The decrease was primarily due to the Company's program to reduce and/or refinance higher-cost, long-term debt. This decrease was partially offset by the replacement of $62 million of preferred stock with COMRPS in the third quarter of 1997.

Other Income and Deductions Excluding Interest Charges

Other income and deductions excluding interest charges decreased in 1998 by $77 million to a deduction of $73 million. The decrease was primarily due to the settlement of litigation arising from the shutdown of Salem recognized in 1997 and losses from the Company's non-utility ventures, which are accounted for under the equity method, partially offset by interest income on a gross receipts tax refund.

Other income and deductions excluding interest charges increased in 1997 by $6 million to $4 million. The increase was primarily due to the settlement of litigation arising from the shutdown of Salem, partially offset by losses from the Company's non-utility ventures. Also offsetting the increase was the write-off of one of the Company's telecommunications investments as a result of the auctioning of personal communications systems "C-block" licenses by the Federal Communication Commission.

Income Taxes

Income taxes increased in 1998 by $27 million to $320 million. The Company's effective income tax rate decreased, however, from 46.5% to 37.5% in 1998 primarily as a result of full normalization of deferred taxes associated with deregulated generation plant.

Income taxes decreased in 1997 by $47 million to $293 million. The Company's effective income tax rate increased, however, from 39.7% to 46.5% in 1997 primarily attributable to reduced tax depreciation benefits from plant and regulatory assets which were not fully normalized for ratemaking purposes.

Preferred Stock Dividends

Preferred stock dividends decreased in 1998 by $4 million to $13 million and decreased in 1997 by $1 million to $17 million. The decreases were primarily a result of the replacement of $62 million of preferred stock with COMRPS in the third quarter of 1997.

Discussion of Liquidity and Capital Resources

The Company's capital resources are primarily provided by internally generated cash flows from utility operations and, to the extent necessary, external financing. Such capital resources are used to fund the Company's capital requirements, including investments in new and existing ventures, to repay maturing debt and to make preferred and common stock dividend payments.

Cash flows from operations were $1,433 million in 1998 as compared to $1,038 million in 1997 and $1,172 million in 1996. The increase in 1998 was principally attributable to improved operating results and changes in working capital.

Cash flows used in investing activities were $462 million in 1998 as compared to $573 million in 1997 and $663 million in 1996. Expenditures under the Company's construction program decreased to $415 million in 1998. Net funds invested in diversified activities in 1998 were $47 million, consisting of $17 million for telecommunications ventures, $21 million for nuclear plant decommissioning trust funds and $9 million for other deposits and ventures. In 1997 and 1996, funds used in similar activities were $83 million and $114 million, respectively.

Cash flows used in financing activities were $956 million in 1998 as compared to $461 million in 1997 and $501 million in 1996. The increase in 1998 was primarily attributable to increased retirement of long-term debt partially offset by lower dividends on common stock. During 1998, in anticipation of competition, which is expected to reduce cash flows, the Company reduced its dividend payment requirements by reducing its common stock dividend to $1 per share. The decrease in 1997 was primarily due to fewer retirements of higher-cost debt.

The Company's capital expenditures are currently estimated to be $440 million in 1999. Certain facilities under construction and to be constructed may require permits and licenses which the Company has no assurance will be granted. Capital expenditures do not include investments in joint ventures including investments related to the Company's strategy to expand its generation portfolio. See "Outlook-Expansion of Generation Portfolio." The Company may use internally generated funds or external financing or a combination of both to finance any acquisition.

The Company meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under bank credit facilities. The Company has a $900 million unsecured revolving credit facility with a group of banks which consists of a $450 million 364-day credit agreement and a $450 million three-year credit agreement. The Company uses the credit facility principally to support its $600 million commercial paper program. There was no debt outstanding under this credit facility at December 31, 1998. The Company had $525 million of short-term debt, consisting of $125 million of commercial paper, and a $400 million term loan, outstanding at December 31, 1998.

At December 31, 1998, the Company's embedded cost of debt was 6.65% with 29% of the Company's long-term debt having floating rates.

At December 31, 1998, the Company's capital structure consisted of 44.2% common equity; 8.4% preferred stock and COMRPS (which comprised 5.1% of the Company's total capitalization structure); and 47.4% long-term debt.

In the Final Restructuring Order, the PUC authorized the Company to securitize up to $4 billion of its allowed $5.26 billion stranded cost recovery through the issuance of transition bonds (Transition Bonds). The proceeds of any securitization are required to be used by the Company principally to reduce its stranded costs and related capitalization. The Company currently proposes to securitize its allowed stranded asset recovery, up to the maximum amount authorized by the PUC, through the issuance of Transition Bonds by a special purpose subsidiary (SPS). The Transition Bonds will be obligations of the SPS secured by intangible transition property (ITP). ITP represents the irrevocable right of the Company or its assignee, to collect non-bypassable charges from customers to recover stranded costs. The Transition Bonds will be included in the consolidated capitalization of the Company. Because the Transition Bonds will be obligations of the SPS, payable from the ITP owned by the SPS, the Company does not expect the issuance of Transition Bonds to adversely affect the ratings on the Company's securities which remain outstanding after issuance of Transition Bonds.

In anticipation of the issuance of Transition Bonds, the Company's Board of Directors authorized the repurchase of up to 25 million shares of the Company's common stock from time to time through open market, privately negotiated and/or other types of transactions. The Company has entered into forward purchase agreements to be settled from time to time, at the Company's election on either a physical, net share or net cash basis. The amount at which these agreements can be settled is dependent principally upon the market price of the Company's common stock as compared to the forward purchase price per share and the number of shares to be settled. If these agreements had been settled on a net share basis at December 31, 1998, based on the closing price of the Company's common stock on that date, the Company would have received approximately 4.6 million shares of the Company's common stock.

The Company has entered into treasury forwards and forward starting interest rate swaps to manage interest rate exposure associated with the anticipated issuance of Transition Bonds. The fair value of ($4.7 million) was based on the present value difference between the contracted rate (i.e., hedged rate) and the market rates at December 31, 1998.

The aggregate change in fair value of the Transition Bond derivative instruments that would have resulted from a hypothetical 50 basis point decrease in the spot yield at December 31, 1998 is estimated to be $128 million. If the derivative instruments had been terminated at December 31, 1998, this estimated fair value represents the amount to be paid by the Company to the counterparties.

The aggregate change in fair value of the Transition Bond derivative instruments that would have resulted from a hypothetical 50 basis point increase in the spot yield at December 31, 1998 is estimated to be $113 million. If the derivative instruments had been terminated at December 31,1998, this estimated fair value represents the amount to be paid by the counterparties to the Company.

Outlook

The Company is entering a period of financial uncertainty as a result of the deregulation of its electric generation operations. Under the terms of the Final Restructuring Order, revenues from regulated rates will decrease. In addition, the Company will sell an increasing portion of its energy at market-based rates. The Company believes that the deregulation of its electric generation operations and other regulatory initiatives designed to encourage competition will increase the Company's risk profile by changing and increasing the number of factors upon which the Company's financial results are dependent. This may result in more volatility in the Company's future results of operations. The Company believes that it has significant advantages that will strengthen its position in the increasingly competitive electric generation

environment. These advantages include the ability to produce electricity at a low variable-cost and the demonstrated ability to market power in the competitive wholesale markets.

The Company's future financial condition and results of operations are substantially dependent upon the effects of the Final Restructuring Order and retail and wholesale competition for generation services. Additional factors that affect the Company's financial condition and results of operations include operation of nuclear generating facilities, Year 2000 issues, new accounting pronouncements, inflation, weather, compliance with environmental regulations and the profitability of the Company's investments in new ventures.

Final Restructuring Order

The Final Restructuring Order contains a number of provisions which the Company expects will significantly impact its future results of operations and financial condition, including mandated rate reductions, extended rate caps, provisions designed to enhance competition for generation services, the amortization of the Company's stranded cost recovery and the securitization of stranded cost recovery.

The Final Restructuring Order mandates retail electric rate reductions of 8% in 1999 and 6% in 2000 from rates in existence on December 31, 1996. Based on the estimated annual sales of the Company in the Final Restructuring Order, these rate reductions will reduce the Company's revenue from retail electric sales by $270 million and $200 million in 1999 and 2000, respectively. The Company's revenue from retail electric sales will be further reduced to the extent that customers purchase generation service from alternate EGS.

The Final Restructuring Order caps the Company's retail transmission and distribution rates at their current levels through June 30, 2005. The Final Restructuring Order also established rate caps for generation services, consisting of the charge for stranded cost recovery and a charge for energy and capacity, through 2010. The rate caps will limit the Company's ability to pass cost increases through to customers.

The Final Restructuring Order contains a number of provisions which are designed to encourage competition for generation services. The Final Restructuring Order establishes an above-market shopping credit for generation services, equivalent to the Company's energy and capacity charge, in order to provide an economic incentive for customers to choose an alternate EGS. If market prices of retail generation services remain below the shopping credits for generation established by the Final Restructuring Order, this economic incentive to choose an alternate EGS will continue. If, on the other hand, market prices of retail generation services exceed the shopping credits for generation, customers will have an economic incentive to purchase generation services from the Company as the provider of last resort (PLR) at below market rates. Additionally, if on January 1, 2001 and January 1, 2003, less than 35% and 50%, respectively, of the Company's residential and commercial customers are obtaining generation service from alternate EGS, the non-shopping customers will be randomly assigned to EGS, including those affiliated with the Company, to meet these thresholds. Further, on January 1, 2001, 20% of all the Company's residential customers, whether or not such customers are obtaining generation service from an alternate EGS, will be assigned to a PLR other than the Company. Such alternate supplier will be selected by a PUC-approved bidding process. The right to provide this competitive default service will be rebid annually, and if the number of residential customers served by this service falls below 17%, further random selection of customers will be assigned to achieve the 20% level.

The Company's recovery of stranded costs is based on the level of transition charges established in the Final Restructuring Order and the projected annual retail sales in the Company's service territory. Recovery of transition charges for stranded costs will be included in operating revenue and are expected to be $552 million in 1999, increasing to $932 million by 2010, the final year of stranded cost recovery. Amortization of the Company's stranded cost recovery, which is a regulatory asset, will be included in depreciation and amortization, beginning in 1999 at a level of ($14) million and increasing by 2010 to $879 million. The Company is allowed a 10.75% return on the unamortized balance. As a result of this amortization schedule, the Company expects its earnings to be disproportionately benefited by the recovery of stranded assets in the early years of the transition period declining over the life of the recovery as the balance of the unamortized regulatory asset is reduced.

Under the Final Restructuring Order, the Company may securitize up to $4 billion of its $5.26 billion of stranded cost recovery through the issuance of Transition Bonds. The rate reductions and rate caps of the Final Restructuring Order anticipate the benefits of securitization and no adjustment in the Company's base rates will be made upon the issuance of Transition Bonds. As a result of the 10.75% allowed return on the unamortized balance of stranded cost recovery and expected costs of securitization substantially below this allowed return, the Company anticipates that successful securitization, resulting in a reduction of its common equity, will improve the Company's future financial results.

Competition

The Company competes in both the retail electric generation market in Pennsylvania and the wholesale electric generation market nationally. Competition for electric generation services is expected to create new uncertainties in the utility industry. These uncertainties include future prices of generation services in both the wholesale and retail markets; potential changes in the Company's customer profiles, both at the retail level where change is expected to be ongoing as a result of customer choice, and between the retail and wholesale markets; and supply and demand volatility.

Retail competition for generation supply commenced in January 1999, with two-thirds of Pennsylvania electric utility consumers having the right to choose their suppliers of generation service. The Company is actively competing for a share of the generation supply market in its traditional service territory through PECO Energy Distribution as the PLR for customers who do not or cannot choose an alternate EGS and throughout Pennsylvania through Exelon Energy, the Company's new competitive supplier. Generation services provided by PECO Energy Distribution are at the energy and capacity charge mandated by the Final Restructuring Order. Generation services offered by Exelon Energy are at competitive market prices. Customers who continue to take generation service from PECO Energy Distribution may choose an alternate generation supplier at any time. As of

January 12, 1999, approximately 12% of the Company's residential and small commercial customers and approximately 50% of its large commercial and industrial customers had selected an alternate EGS. As of that date, Exelon Energy is providing generation service to approximately 135,000 business and residential customers throughout Pennsylvania. Because the energy and capacity charge (shopping credit) established by the PUC in the Restructuring Order remains above current retail market prices for generation services, including those offered by Exelon Energy, the Company's retail revenues will be reduced to the extent customers choose an alternate EGS, including Exelon Energy. To the extent that the Company cannot replace lost retail sales through PECO Energy Distribution with retail sales by Exelon Energy, the Company will be required to sell a larger portion of its energy and capacity in the wholesale market. Since prices in the wholesale market are currently lower on average than those charged in the competitive retail market, this will adversely affect the Company's revenues and profit margins.

The Company is a low variable-cost electricity producer, which puts it in a favorable position to take advantage of opportunities in the electric retail and wholesale generation markets. The Company's competitive position and its future financial condition and results of operations are dependent on the Company's ability to successfully operate its low variable-cost power plants and market its power effectively in competitive wholesale markets.

The Company competes in the wholesale market by selling the energy and capacity from the Company's installed capacity not utilized in the retail market and buying and selling energy from third parties. The Company enters into both long-term and short-term commitments to buy and sell power. Currently, the Company's long-term commitments, together with the energy the Company expects to market from the Company's installed capacity, make the Company a net power seller. This long position, however, exposes the Company to the risk of declining revenues in periods of low wholesale demand for generation services. See Note 5 of Notes to Consolidated Financial Statements.

There is an initiative in the Pennsylvania legislature to deregulate the gas industry, which has the support of the governor. The Company cannot predict whether the Pennsylvania legislature will enact legislation that deregulates the gas industry or whether the governor will ultimately sign into law any such legislation. The Company cannot predict the ultimate effect of gas industry deregulation on its future financial condition or results of operations.

Regulation and Operation of Nuclear Generating Facilities

The Company's financial condition and results of operations are in part dependent on the continued successful operation of its nuclear generating facilities. The Company's nuclear generating facilities represent 44% of its installed generating capacity. Because of the Company's reliance on its nuclear generating units, any changes in regulations by the Nuclear Regulatory Commission (NRC) requiring additional investments or resulting in increased operating costs of nuclear generating units could adversely affect the Company.

During 1998, Company-operated nuclear plants operated at an 86% weighted-average capacity factor and Company-owned nuclear plants operated at an 83% weighted-average capacity factor. Company-owned nuclear plants produced 39% of the Company's electricity. Nuclear generation is currently the most cost-effective way for the Company to meet customer needs and commitments for sales to other utilities. See "Expansion of Generation Portfolio".

New Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," to establish accounting and reporting standards for derivatives. The new standard requires recognizing all derivatives as either assets or liabilities on the balance sheet at their fair value and specifies the accounting for changes in fair value depending upon the intended use of the derivative. The new standard is effective for fiscal years beginning after June 15, 1999. The Company expects to adopt SFAS No. 133 in the first quarter of 2000. The Company is in the process of evaluating the impact of SFAS No. 133 on its financial statements.

In November 1998, the FASB's Emerging Issues Task Force issued EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 outlines attributes that may be indicative of an energy trading operation and gives further guidance on the accounting for contracts entered into by an energy trading operation. This accounting guidance requires mark-to-market accounting for contracts considered to be a trading activity. EITF 98-10 is applicable for fiscal years beginning after December 15, 1998 with any impact recorded as a cumulative effect adjustment through retained earnings at the date of adoption. At December 31, 1998, the Company has evaluated its wholesale marketing operation and related contracts under the guidance provided in EITF 98-10. For those contracts entered into in the over-the-counter market and considered to be a trading activity, the Company believes the impact to be immaterial. However, with respect to the long-term commitments considered to be trading activities, the Company is continuing to evaluate these commitments and the impact of adopting EITF 98-10.

Other Factors

Annual and quarterly operating results can be significantly affected by weather. Since the Company's peak demand is in the summer months, temperature variations in summer months are generally more significant than variations during winter months.

Inflation affects the Company through increased operating costs and increased capital costs for utility plant. As a result of the rate caps imposed under the Final Restructuring Order and expected price pressures due to competition, the Company may have a limited opportunity to pass the costs of inflation through to customers.

The Company's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws. Additionally, under federal and state environmental laws, the Company is generally liable for the costs of remediating environmental contamination of property now or formerly owned by the Company and of property contaminated by hazardous substances generated

by the Company. The Company owns or leases a number of real estate parcels, including parcels on which its operations or the operations of others may have resulted in contamination by substances which are considered hazardous under environmental laws. The Company is currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

The Company has identified 28 sites where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. The Company is presently engaged in performing various levels of activities at these sites, including initial evaluation to determine the existence and nature of the contamination, detailed evaluation to determine the extent of the contamination and the necessity and possible methods of remediation, and implementation of remediation. The Pennsylvania Department of Environmental Protection has approved the Company's clean-up of three sites. Eight other sites are currently under some degree of active study and/or remediation.

As of December 31, 1998 and 1997, the Company had accrued $60 and $63 million, respectively, for environmental investigation and remediation costs, including $33 and $35 million, respectively, for MGP investigation and remediation that currently can be reasonably estimated. The Company expects to expend $3 million for environmental remediation activities in 1999. The Company cannot predict whether it will incur other significant liabilities for any additional investigation and remediation costs at these or additional sites identified by the Company, environmental agencies or others, or whether such costs will be recoverable from third parties.

For a discussion of other contingencies, see Note 5 of Notes to Consolidated Financial Statements.

Year 2000 Readiness Disclosure

Due to the severity of the potential impact of the Year 2000 Issue (Y2K Issue) on the electric utility industry, the Company has adopted a comprehensive schedule to achieve Y2K readiness by the time specified by the NRC. The Company has dedicated extensive resources to its Y2K Project (Project) and believes the project is progressing on schedule.

The Project is addressing the issue resulting from computer programs using two digits rather than four to define the applicable year and other programming techniques that constrain date calculations or assign special meanings to certain dates. Any of the Company's computer systems that have date-sensitive software or microprocessors may recognize a date using "00" as the year 1900 rather than the year 2000. This could result in a system failure or miscalculations causing disruptions of operations, including, a temporary inability to process transactions, send bills, operate generating stations, or engage in similar normal business activities.

The Company has determined that it will be required to modify, convert or replace significant portions of its software and a subset of its system hardware and embedded technology so that its computer systems will properly utilize dates beyond December 31, 1999. The Company presently believes that with these modifications, conversions and replacements the effect of the Y2K Issue on the Company can be mitigated. If such modifications, conversions and replacements are not made, or are not completed in a timely manner, the Y2K Issue could have a material impact on the operations and financial condition of the Company. The costs associated with this potential impact are not presently quantifiable.

The Company is utilizing both internal and external resources to reprogram, or replace and test software and computer systems for the Project. The Project is scheduled for completion by July 1, 1999, except for a small number of modifications, conversions or replacements that are impacted by vendor dates and/or are being incorporated into scheduled plant outages between July and October 1999.

The Project is divided into four major sections – Information Technology Systems (IT Systems), Embedded Technology (devices used to control, monitor or assist the operation of equipment, machinery or plant), Supply Chain (third-party suppliers and customers), and Contingency Planning. The general phases common to all sections are: (1) inventorying Y2K items; (2) assigning priorities to identified items; (3) assessing the Y2K readiness of items determined to be material to the Company; (4) converting material items that are determined not to be Y2K ready; (5) testing material items; and (6) designing and implementing contingency plans for each critical Company process. Material items are those believed by the Company to have a risk involving the safety of individuals, may cause damage to property or the environment, or affect revenues.

The IT Systems section includes both the conversion of applications software that is not Y2K ready and the replacement of software when available from the supplier. The Company estimates that the software conversion phase was approximately 66% complete at January 27, 1999, and the remaining conversions are expected to be completed by the scheduled end date. The Company has been experiencing slippage in delivery dates of vendor supplied products which may have a minor impact on the July 1, 1999 target completion date. Contingency planning for IT Systems is scheduled to be completed by July 1, 1999 with an interim date of March 31, 1999 that addresses PUC contingency planning requirements. The Project has identified 380 critical systems of which 238 are IT Systems. The current readiness status of IT Systems is set forth below:

Number of Systems	Progress Status
79 Systems	Y2K Ready
65 Systems	In Testing
87 Systems	In Active Code Modification, Or Package Upgrading
7 Systems	Not Started

The Embedded Technology section consists of hardware and systems software other than IT Systems. The Company estimates that the Embedded Technology section was approximately 75% complete at January 27, 1999. The remaining conversions are on schedule to be tested and ready by July 1, 1999, except for a small number of systems which will be extended into the fall of 1999 because their final tests will occur during a planned generating plant outage. Contingency planning for Embedded Technology is scheduled to be completed by July 1, 1999 with an interim date of March 31, 1999 that addresses PUC contingency planning requirements. The Project has identified 142 critical Embedded Technology systems. The current readiness status of those systems is set forth below:

Number of Systems	Progress Status
31 Systems	Y2K Ready
29 Systems	In Final Quality Review
76 Systems	In Progress
6 Systems	Not Started

The Supply Chain section includes the process of identifying and prioritizing critical suppliers and communicating with them about their plans and progress in addressing the Y2K Issue. The Company initiated formal communications with all of its critical suppliers to determine the extent to which the Company may be vulnerable to their Y2K issues. The process of evaluating these critical suppliers has commenced and is scheduled to be completed by March 31, 1999.

The Company, like other companies, is interconnected with many businesses, including electric utilities, natural gas pipelines and municipalities. The Company is working with businesses where interconnections exist to determine and monitor their Y2K readiness efforts. In addition, the Company is currently developing contingency plans to address how to respond to events which may disrupt normal operations. These plans address Y2K risk scenarios that cross departmental, business unit and industry lines as well as specific risks from various internal and external sources, including supplier readiness. Emergency plans already exist that cover various aspects of the Company's business. These plans are being reviewed and updated, as needed, to address the Y2K Issue. The Company is also participating in industry contingency planning efforts.

The estimated total cost of the Project is $75 million, the majority of which will be incurred during testing. This estimate includes the Company's share of Y2K costs for jointly owned facilities. The total amount expended on the Project through December 31, 1998 was $21 million. The Company expects to fund the Project from operating cash flows.

The Company's failure to become Y2K ready could result in an interruption in or a failure of certain normal business activities or operations. In addition, there can be no assurance that the systems of other companies on which the Company's systems rely or with which they communicate will be converted in a timely manner, or that a failure to convert by another company, or a conversion that is incompatible with the Company's systems, will not have a material adverse effect on the Company. Such failures could materially and adversely affect the Company's results of operations, liquidity and financial condition. The Company is currently developing contingency plans to address how to respond to events that may disrupt normal operations, including activities with PJM Interconnection, LLC.

The costs of the Project and the date on which the Company plans to complete the Y2K modifications are based on estimates, that were derived utilizing numerous assumptions of future events, including the continued availability of certain resources, third-party modification plans and other factors, such as regulatory requirements that impact key systems. There can be no assurance that these estimates will be achieved. Actual results could differ materially from the projections. Specific factors that might cause a material change include, but are not limited to, the availability and cost of trained personnel, the ability to locate and correct all relevant computer programs and microprocessors.

The Project is expected to significantly reduce the Company's level of uncertainty about the Y2K Issue. The Company believes that the completion of the Project, as scheduled, minimizes the possibility of significant interruptions of normal operations.

Expansion of Generation Portfolio

The Company established specific goals to increase its generation capacity from 9 gigawatts to 25 gigawatts by 2003. The Company is targeting a balanced portfolio of nuclear, hydro and clean burning fossil capacity through the acquisition of plants and long-term supply agreements. In order to meet this strategic objective the Company may require significant capital resources.

In October 1998, the Company through AmerGen Energy Company, LLC, a 50% owned joint venture with British Energy, Inc., entered into a definitive asset purchase agreement with GPU, Inc. (GPU) to acquire GPU's 786 megawatt Three Mile Island Unit No. 1 Nuclear Generating Facility for approximately $23 million in cash, $77 million for nuclear fuel payable over five years and certain contingent payments based upon future wholesale market prices. The Company currently expects the acquisition, which is subject to various regulatory approvals, to close by mid-year 1999.

Corporate Restructuring

In 1999, the Company's common shareholders will vote on management proposal for the formation of a holding company. The holding company will be formed through the exchange of PECO Energy common stock for common stock of the holding company. As a result, the Company will become a wholly owned subsidiary of the holding company. The formation of the holding company will not affect the Company's other securities. Management has proposed the formation of the holding company to facilitate the disaggregation of the Company's transmission and distribution, generation and unregulated businesses and corporate central services in order to create increased financial, management and organizational flexibility.

Forward-Looking Statements

Except for the historical information contained herein, certain of the matters discussed in this Report are forward-looking statements which are subject to risks and uncertainties. The factors that could cause actual results to differ materially include those discussed herein as well as those listed in Note 5 of Notes to Consolidated Financial Statements and other factors discussed in the Company's filings with the Securities and Exchange Commission. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this Report. The Company undertakes no obligation to publicly release any revision to these forward-looking statements to reflect events or circumstances after the date of this Report.

Report of Independent Accountants

To the Shareholders and Board of Directors
of PECO Energy Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, cash flows and changes in common shareholders' equity and preferred stock present fairly, in all material respects, the financial position of PECO Energy Company and Subsidiary Companies at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. 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 of these statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

Philadelphia, Pennsylvania
February 5, 1999

Consolidated Statements of Income

For the Years Ended December 31,	1998	1997	1996
			Thousands of Dollars
Operating Revenues			
Electric	**$ 4,810,840**	$ 4,166,669	$ 3,854,836
Gas	**399,642**	451,232	428,814
Total Operating Revenues	**5,210,482**	4,617,901	4,283,650
Operating Expenses			
Fuel and Energy Interchange	**1,751,819**	1,290,164	972,380
Operating and Maintenance	**1,128,792**	1,431,420	1,274,222
Early Retirement and Separation Programs	**124,200**	—	—
Depreciation and Amortization	**642,842**	580,595	489,001
Taxes Other Than Income	**279,515**	310,091	299,546
Total Operating Expenses	**3,927,168**	3,612,270	3,035,149
Operating Income	**1,283,314**	1,005,631	1,248,501
Other Income and Deductions			
Interest Expense	**(330,842)**	(372,857)	(382,443)
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership, which holds Solely Subordinated Debentures of the Company	**(30,694)**	(28,990)	(26,723)
Allowance for Funds Used During Construction	**3,522**	21,771	19,947
Settlement of Salem Litigation	**—**	69,800	—
Other, net	**(73,268)**	(66,028)	(1,976)
Total Other Income and Deductions	**(431,282)**	(376,304)	(391,195)
Income Before Income Taxes and Extraordinary Item	**852,032**	629,327	857,306
Income Taxes	**319,654**	292,769	340,101
Income Before Extraordinary Item	**532,378**	336,558	517,205
Extraordinary Item (net of income taxes of $13,757 and $1,290,961 for 1998 and 1997, respectively)	**(19,654)**	(1,833,664)	—
Net Income (Loss)	**512,724**	(1,497,106)	517,205
Preferred Stock Dividends	**13,109**	16,804	18,036
Earnings (Loss) Applicable to Common Stock	**$ 499,615**	$ (1,513,910)	$ 499,169
Average Shares of Common Stock Outstanding *(Thousands)*	**223,219**	222,543	222,490
Basic Earnings per Average Common Share Before Extraordinary Item *(Dollars)*	**$ 2.33**	$ 1.44	$ 2.24
Extraordinary Item *(Dollars)*	**$ (0.09)**	$ (8.24)	$ —
Basic Earnings per Average Common Share *(Dollars)*	**$ 2.24**	$ (6.80)	$ 2.24
Diluted Earnings per Average Common Share Before Extraordinary Item *(Dollars)*	**$ 2.32**	$ 1.44	$ 2.24
Extraordinary Item *(Dollars)*	**$ (0.09)**	$ (8.24)	$ —
Diluted Earnings per Average Common Share *(Dollars)*	**$ 2.23**	$ (6.80)	$ 2.24
Dividends per Common Share *(Dollars)*	**$ 1.00**	$ 1.80	$ 1.755

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the Years Ended December 31,	1998	1997	1996
			Thousands of Dollars
Cash Flows from Operating Activities			
Net Income (Loss)	**$ 512,724**	$ (1,497,106)	$ 517,205
Extraordinary Item (net of income taxes)	**(19,654)**	(1,833,664)	—
Income Before Extraordinary Item	**532,378**	336,558	517,205
Adjustments to reconcile Net Income to Net Cash provided by Operating Activities:			
Depreciation and Amortization	**704,718**	664,294	566,412
Deferred Income Taxes	**(115,640)**	(17,228)	166,770
Amortization of Investment Tax Credits	**(18,066)**	(18,201)	(15,979)
Early Retirement and Separation Charge	**125,000**	—	—
Salem Litigation Settlement	**—**	69,800	—
Deferred Energy Costs	**5,818**	(5,652)	(66,151)
Amortization of Leased Property	**59,923**	39,100	31,400
Changes in Working Capital:			
Accounts Receivable	**15,590**	(289,610)	53,681
Inventories	**14,192**	28,628	(2,729)
Accounts Payable	**8,971**	93,881	(86,765)
Other Current Assets and Liabilities	**54,263**	58,539	(25,040)
Other Deferred Credits - Other	**49,948**	78,846	(4,609)
Other Items affecting Operations	**(4,190)**	(804)	38,050
Net Cash Flows from Operating Activities	**1,432,905**	1,038,151	1,172,245
Cash Flows from Investing Activities			
Investment in Plant	**(415,331)**	(490,200)	(548,854)
Increase in Other Investments	**(46,742)**	(83,261)	(114,126)
Net Cash Flows from Investing Activities	**(462,073)**	(573,461)	(662,980)
Cash Flows from Financing Activities			
Change in Short-Term Debt	**123,500**	114,000	287,500
Proceeds from Exercise of Stock Options	**50,700**	117	11,301
Retirement of Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership	**(80,794)**	(61,895)	—
Issuance of Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership	**78,105**	50,000	—
Issuance of Long-Term Debt	**13,486**	161,813	43,700
Retirement of Long-Term Debt	**(841,755)**	(283,303)	(427,463)
Loss on Reacquired Debt	**6,753**	22,752	24,724
Dividends on Preferred and Common Stock	**(236,307)**	(417,383)	(411,569)
Capital Lease Payments	**(59,923)**	(39,100)	(31,400)
Other Items Affecting Financing	**(9,918)**	(7,522)	2,575
Net Cash Flows from Financing Activities	**(956,153)**	(460,521)	(500,632)
Increase in Cash and Cash Equivalents	**14,679**	4,169	8,633
Cash and Cash Equivalents at beginning of period	**33,404**	29,235	20,602
Cash and Cash Equivalents at end of period	**$ 48,083**	$ 33,404	$ 29,235

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

At December 31,	1998	1997
		Thousands of Dollars
Assets		
Utility Plant		
Electric-Transmission & Distribution	**$ 3,833,780**	$ 3,617,666
Electric-Generation	**1,713,430**	1,434,895
Gas	**1,131,999**	1,071,819
Common	**407,320**	302,672
	7,086,529	6,427,052
Less Accumulated Provision for Depreciation	**2,891,321**	2,690,824
	4,195,208	3,736,228
Nuclear Fuel, net	**141,907**	147,359
Construction Work in Progress	**272,590**	611,204
Leased Property, net	**154,308**	175,933
Net Utility Plant	**4,764,013**	4,670,724
Current Assets		
Cash and Temporary Cash Investments	**48,083**	33,404
Accounts Receivable, net		
Customers	**97,527**	173,350
Other	**213,229**	139,996
Inventories, at average cost		
Fossil Fuel	**79,488**	84,858
Materials and Supplies	**82,068**	90,890
Deferred Energy Costs-Gas	**29,847**	35,665
Deferred Generation Costs Recoverable in Current Rates	**—**	424,497
Other	**19,013**	20,115
Total Current Assets	**569,255**	1,002,775
Deferred Debits and Other Assets		
Competitive Transition Charge	**5,274,624**	5,274,624
Recoverable Deferred Income Taxes	**614,445**	590,267
Deferred Non-Pension Postretirement Benefits Costs	**90,915**	97,409
Investments	**550,904**	515,835
Loss on Reacquired Debt	**77,165**	83,918
Other	**107,042**	121,016
Total Deferred Debits and Other Assets	**6,715,095**	6,683,069
Total Assets	**$ 12,048,363**	$ 12,356,568

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets *(Continued)*

At December 31,	1998	1997
		Thousands of Dollars
Capitalization and Liabilities		
Capitalization		
Common Shareholders' Equity		
Common Stock	**$ 3,589,031**	$ 3,517,731
Other Paid-In Capital	**1,236**	1,239
Retained Earnings (Accumulated Deficit)	**(532,925)**	(792,239)
	3,057,342	2,726,731
Preferred and Preference Stock		
Without Mandatory Redemption	**137,472**	137,472
With Mandatory Redemption	**92,700**	92,700
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership, which holds Solely Subordinated Debentures of the Company	**349,355**	352,085
Long-Term Debt	**2,919,592**	3,853,141
Total Capitalization	**6,556,461**	7,162,129
Current Liabilities		
Notes Payable	**525,000**	401,500
Long-Term Debt Due Within One Year	**361,523**	247,087
Capital Lease Obligations Due Within One Year	**69,011**	55,808
Accounts Payable	**316,292**	323,816
Taxes Accrued	**170,495**	66,397
Interest Accrued	**61,515**	77,911
Deferred Income Taxes	**14,168**	185,696
Other	**217,416**	260,457
Total Current Liabilities	**1,735,420**	1,618,672
Deferred Credits and Other Liabilities		
Capital Lease Obligations	**85,297**	120,125
Deferred Income Taxes	**2,376,792**	2,297,042
Unamortized Investment Tax Credits	**299,999**	318,065
Pension Obligation	**219,274**	211,596
Non-Pension Postretirement Benefits Obligation	**421,083**	324,850
Other	**354,037**	304,089
Total Deferred Credits and Other Liabilities	**3,756,482**	3,575,767
Commitments and Contingencies (Note 5)		
Total Capitalization and Liabilities	**$ 12,048,363**	$ 12,356,568

See Notes to Consolidated Financial Statements.

Consolidated Statements of Changes in Common Shareholders' Equity and Preferred Stock

All Amounts in Thousands	Common Stock Shares	Common Stock Amount	Other Paid-In Capital	Retained Earnings (Accumulated Deficit)	Preferred Stock Shares	Preferred Stock Amount
Balance at January 1, 1996	222,172	$ 3,506,313	$ 1,326	$ 1,023,708	2,921	$ 292,067
Net Income				517,205		
Cash Dividends Declared						
Preferred Stock						
(at specified annual rates)				(21,042)		
Common Stock ($1.755 per share)				(390,527)		
Expenses of Capital Stock Activity				(275)		
Capital Stock Activity						
Long-Term Incentive Plan Issuances	370	11,301		(2,028)		
Balance at December 31, 1996	222,542	3,517,614	1,326	1,127,041	2,921	292,067
Net Loss				(1,497,106)		
Cash Dividends Declared						
Preferred Stock						
(at specified annual rates)				(16,804)		
Common Stock ($1.80 per share)				(400,578)		
Expenses of Capital Activity				97		
Stock Repurchase Forward Contract				(4,889)		
Capital Stock Activity						
Long-Term Incentive Plan Issuances	5	117				
Preferred Stock Redemptions			(87)		(619)	(61,895)
Balance at December 31, 1997	**222,547**	**$ 3,517,731**	**$ 1,239**	**$ (792,239)**	**2,302**	**$ 230,172**
Net Income				**512,724**		
Cash Dividends Declared						
Preferred Stock						
(at specified annual rates)				**(13,109)**		
Common Stock ($1.00 per share)				**(223,198)**		
Expenses of Capital Stock Activity				**2,731**		
Stock Repurchase Forward Contract				**(7,677)**		
Capital Stock Activity						
Long-Term Incentive Plan Issuances	**2,137**	**71,300**	**(3)**	**(12,157)**		
Balance at December 31, 1998	**224,684**	**$ 3,589,031**	**$ 1,236**	**$ (532,925)**	**2,302**	**$ 230,172**

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. Significant Accounting Policies

General

The consolidated financial statements of PECO Energy Company (the Company) include the accounts of its utility subsidiary companies, all of which are wholly owned. Accounting policies for all of the Company's operations are in accordance with generally accepted accounting principles (GAAP). Accounting policies for regulated operations are also in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC). The Company has unconsolidated nonutility subsidiaries which are not material. The unconsolidated subsidiaries are accounted for under the equity method.

Use of Estimates

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 and 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.

Estimates are used by the Company in accounting for unbilled revenue, the allowance for uncollectible accounts, purchased gas adjustment clause, depreciation and amortization, taxes, reserves for contingencies, employee benefits, certain fair value and recoverability determinations, and nuclear outage costs, among others.

Accounting for the Effects of Regulation

The Company accounts for all of its electric transmission and distribution and gas operations in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," requiring the Company to record the financial statement effects of the rate regulation to which such operations are currently subject. If a separable portion of the Company's business no longer meets the provisions of SFAS No. 71, the Company is required to eliminate the financial statement effects of regulation for that portion. Effective December 31, 1997, the Company determined that the electric generation portion of its business no longer met the criteria of SFAS No. 71 and, accordingly, implemented SFAS No. 101, "Regulated Enterprises - Accounting for the Discontinuation of FASB Statement No. 71," for that portion of its business.

Revenues

Electric and gas revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Company accrues an estimate for the unbilled amount of energy delivered or services provided to customers.

Purchased Gas and Energy Cost Adjustment Clauses

The Company's gas rates are subject to a fuel adjustment clause designed to recover or refund the difference between the actual cost of purchased gas and the amount included in base rates. Differences between the amounts billed to customers and the actual costs recoverable are deferred and recovered or refunded in future periods by means of prospective quarterly adjustments to rates.

Prior to December 31, 1996, the Company's retail electric rates were subject to an Energy Cost Adjustment (ECA) clause designed to recover or refund the difference between the actual cost of fuel, energy interchange or purchased power and the amount of such costs included in base rates. Effective December 31, 1996, the PUC approved the roll-in of electric energy costs into the base rates charged to the Company's retail electric customers and such rates are no longer subject to the ECA.

Nuclear Fuel

The cost of nuclear fuel is capitalized and charged to fuel expense on the unit of production method. Estimated costs of nuclear fuel disposal are charged to fuel expense as the related fuel is consumed. The Company's nuclear fuel at Peach Bottom Atomic Power Station (Peach Bottom) and Salem Generating Station (Salem) is accounted for as a capital lease. Nuclear fuel at Limerick Generating Station (Limerick) is owned.

Nuclear Outage Costs

Incremental nuclear maintenance and refueling outage costs are accrued over the unit operating cycle. For each unit, an accrual for incremental nuclear maintenance and refueling outage expense is estimated based upon the latest planned outage schedule and estimated costs for the outage. Differences between the accrued and actual expense for the outage are recorded when such differences are known.

Depreciation, Amortization and Decommissioning

Depreciation is provided over the estimated service lives of plant on the straight-line method. Annual depreciation provisions for financial reporting purposes, expressed as a percentage of average depreciable utility plant in service, were approximately 2.8% in 1998, 3.3% in 1997 and 2.9% in 1996. See note 3 for information concerning the change in 1996 to depreciation and amortization.

The Company's current estimate of the costs for decommissioning its ownership share of its nuclear generating stations is currently included in regulated rates and is charged to operations over the expected service life of the related plant. The amounts recovered from customers are deposited in trust accounts and invested for funding of future costs. These amounts, and realized investment earnings thereon, are credited to accumulated depreciation. The Company believes that the amounts being recovered from customers through electric rates will be sufficient to fully fund the unrecorded portion of its decommissioning obligation.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded as a charge to Construction Work in Progress and as a credit to AFUDC

included in Other Income and Deductions. The rates used for capitalizing AFUDC, which averaged 8.63% in 1998, 8.88% in 1997 and 9.38% in 1996, are computed under a method prescribed by regulatory authorities. AFUDC is not included in regular taxable income and the depreciation of capitalized AFUDC is not tax deductible.

Effective January 1, 1998, the Company ceased accruing AFUDC for electric generation-related construction projects and began using SFAS No. 34, "Capitalizing Interest Costs," to calculate the costs during construction of debt funds used to finance its electric generation-related construction projects. The Company recorded capitalized interest of $7 million in 1998.

Gains and Losses on Reacquired Debt

Prior to December 31, 1997, gains and losses on reacquired debt were deferred and amortized to interest expense over the period approved for ratemaking purposes. Effective January 1, 1998, gains and losses on reacquired debt associated with the electric generation portion of the Company's operations are expensed as incurred. Gains and losses on reacquired debt associated with the Company's regulated operations continue to be deferred and amortized to interest expense over the period approved for ratemaking purposes based on management's assessment of the likelihood of recovery.

Income Taxes

Deferred Federal and state income taxes are provided on all significant timing differences between book bases and tax bases of assets and liabilities, transactions that reflect taxable income in a year different than book income and tax carry forwards. Investment tax credits previously used for income tax purposes have been deferred on the Consolidated Balance Sheet and are recognized in book income over the life of the related property. The Company and its subsidiaries file a Consolidated Federal income tax return. Income taxes are allocated to each of the Company's subsidiaries within the consolidated group based on the separate return method.

Derivative Financial Instruments

Hedge accounting is applied only if the derivative reduces the risk of the underlying hedged item and is designated at inception as a hedge, with respect to the hedged item. If a derivative instrument ceased to meet the criteria for deferral, any gains or losses would be currently recognized in income. The Company does not hold or issue derivative financial instruments for trading purposes.

Utility Plant

Effective December 31, 1997, electric generation plant is valued at the lower of original cost or market pursuant to SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of"(SFAS No. 121). All other utility plant continues to be valued at original cost.

Capitalized Software Costs

Software projects which exceed $5 million are capitalized. At December 31, 1998 and 1997, capitalized software costs totaled $84 and $86 million (net of $37 and $29 million accumulated amortization), respectively. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, not to exceed ten years.

New Accounting Pronouncements

In 1998, the Company adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131). SFAS No. 131 supersedes SFAS No. 14, "Financial Reporting for Segments of a Business Enterprise," replacing the "industry segment" approach with the "management" approach. The management approach designates the internal organization that is used by management for making operating decisions and assessing performance as the source of the Company's reportable segments. SFAS No. 131 also requires disclosures about products and services, geographic areas and major customers. The adoption of SFAS No. 131 did not affect the Company's financial condition or results of operations (see note 2).

In 1998, the Company adopted SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," (SFAS No. 132) which revises and standardizes employers' disclosures about pension and other postretirement benefit plans but does not change the measurement or recognition of those plans. The adoption of SFAS No. 132 did not affect the Company's financial condition or results of operations (see note 6).

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS No. 133) to establish accounting and reporting standards for derivatives. The new standard requires recognizing all derivatives as either assets or liabilities on the balance sheet at their fair value and specifies the accounting for changes in fair value depending upon the intended use of the derivative. The new standard will be effective for fiscal years beginning after June 15, 1999. The Company expects to adopt SFAS No. 133 in the first quarter of 2000. The Company is in the process of evaluating the impact of SFAS No. 133 on its financial statements.

In November 1998, the FASB's Emerging Issues Task Force issued EITF 98-10. "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 outlines attributes that may be indicative of an energy trading operation and gives further guidance on the accounting for contracts entered into by an energy trading operation. This accounting guidance requires mark-to-market accounting for contracts considered to be a trading activity. EITF 98-10 is applicable for fiscal years beginning after December 15, 1998 with any impact recorded as a cumulative effect adjustment through retained earnings at the date of adoption. At December 31, 1998, the Company has evaluated its wholesale marketing operation and related contracts under the guidance provided in EITF 98-10. For those contracts entered into in the over-the-counter market and considered to be a trading activity, the Company believes the impact to be immaterial. However, due to the duration, complexity, and uncertainties surrounding the long-term commitments considered to be trading activities, the Company is continuing to evaluate these commitments and the impact of adopting EITF 98-10.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on net income or common shareholders' equity.

2. Nature of Operations and Information about Products and Services

The Company is primarily a vertically integrated public utility that provides retail electric and natural gas service to the public in its traditional service territory and retail electric generation service throughout Pennsylvania in conjunction with Pennsylvania's Customer Choice Program. The Company also engages in the wholesale marketing of electricity on a national basis. The Company participates in joint ventures which provide services such as telecommunications in the Philadelphia metropolitan area. Revenues and expenses associated with these activities, the Customer Choice Program, joint ventures and other projects are reflected in Other Income and Deductions in the Company's Consolidated Statements of Income.

For the Years Ended December 31,	1998	1997	1996
			Thousands of Dollars
Operating Revenues from Electric Operations			
Residential	**$ 1,377,237**	$ 1,357,449	$ 1,370,158
Small commercial and industrial	**783,682**	778,743	748,561
Large commercial and industrial	**1,066,868**	1,077,374	1,098,307
Other	**149,424**	147,523	140,133
Unbilled	**1,409**	19,130	(25,950)
Service territory	**3,378,620**	3,380,219	3,331,209
Interchange sales	**210,965**	58,614	25,991
Sales to other utilities	**1,221,255**	727,836	497,636
Total operating revenues	**$ 4,810,840**	$ 4,166,669	$ 3,854,836
Operating Revenues from Gas Operations			
Residential	**$ 15,968**	$ 16,852	$ 15,716
House heating	**236,430**	265,299	249,507
Commercial and industrial	**124,548**	144,801	132,822
Other	**2,037**	3,228	11,462
Unbilled	**(2,960)**	(969)	(4,250)
Subtotal	**376,023**	429,211	405,257
Other revenues (including gas transported for customers)	**23,619**	22,021	23,557
Total operating revenues	**$ 399,642**	$ 451,232	$ 428,814

3. Rate Matters

Final Restructuring Order

On May 14, 1998, the PUC issued a final order (Final Restructuring Order) approving a Joint Petition for Settlement (Global Settlement) filed by the Company and numerous parties to the Company's restructuring proceeding mandated by the Electricity Generation Competition and Customer Choice Act (Competition Act). The Competition Act provides for the restructuring of the electric utility industry in Pennsylvania, including the deregulation of generation operations and the institution of retail competition for generation supply beginning in 1999. The Final Restructuring Order provided for the recovery of $5.26 billion of stranded costs through transition charges to distribution customers over a 12 year period beginning in 1999 with a 10.75% return on the balance and supercedes all prior orders regarding recovery of generation-related regulatory assets and liabilities. During the 12 year stranded cost recovery period, the Company will amortize the recoverable stranded costs in accordance with the rate schedules determined in the Final Restructuring Order.

The Final Restructuring Order provided for the phase-in of customer choice of electric generation supplier (EGS) for all customers: one-third of the peak load of each customer class on January 1, 1999; one-third on January 2, 1999; and the remainder on January 2, 2000. The Final Restructuring Order also established market share thresholds to ensure that a minimum number of residential and commercial customers choose an EGS. If less than 35% and 50% of residential and commercial customers have chosen an EGS by January 1, 2001 and January 1, 2003, respectively, the number of customers sufficient to meet the necessary threshold levels shall be randomly selected and assigned to an EGS through a PUC-determined process.

Beginning January 1, 1999, electric rates will be unbundled into transmission and distribution components, a Competitive Transition Charge (CTC) for recovery of stranded costs and an energy and capacity charge. Eligible customers who choose an alternative EGS will not be charged the energy and capacity charge or the transmission charge and instead will purchase their electric energy supply and transmission at market-based rates from their EGS. The Company will in turn be reimbursed by the EGS, via the PJM Interconnection, LLC, for the cost of the transmission service at a rate approximately equivalent to the unbundled transmission rate. Also, beginning January 1, 1999, the Company will unbundle its retail electric rates for metering, meter reading and billing and collection services to provide credits to those customers who elect to have an alternative supplier perform these services.

In accordance with the Competition Act and the Final Restructuring Order, the Company's retail electric rates are capped at the year-end 1996 levels (system-wide average of 9.96 cents/kilowatt hour (kWh)) through June 2005. The Final Restructuring Order requires the Company to reduce its retail

electric rates by 8% from the 1996 system-wide average rate on January 1, 1999. The rate decrease will become 6% from January 1, 2000 until January 1, 2001, when the system-wide average rate cap will revert to 9.96 cents/kWh. The transmission and distribution rate component will remain capped at a system-wide average rate of 2.98 cents/kWh through June 30, 2005. Additionally, generation rate caps, defined as the sum of the applicable transition charge and energy and capacity charge, will remain in effect through 2010.

The Final Restructuring Order requires that on January 1, 2001, 20% of all of the Company's residential customers, determined by random selection and without regard to whether such customers are obtaining generation service from an alternate EGS, shall be assigned to a provider of last resort default supplier other than the Company through a PUC-approved bidding process.

The Final Restructuring Order authorizes the issuance of up to $4 billion of transition bonds (Transition Bonds). In preparation for the issuance of Transition Bonds, the Company formed a special purpose subsidiary (SPS). The proceeds of the Transition Bonds are required to be used principally to reduce recoverable stranded costs and related capitalization. The Transition Bonds will be obligations of the SPS, secured by intangible transition property (ITP). ITP represents the irrevocable right of the Company or its assignee, to collect non-bypassable charges from customers to recover stranded costs.

The Company filed complaints in federal and state courts relating to the restructuring orders issued by the PUC in December 1997, January 1998 and February 1998. In addition, numerous other parties filed appeals and cross appeals of these orders. In accordance with the terms of the Final Restructuring Order, all appeals and cross-appeals filed by the signatories to the Global Settlement have been placed in a pending but inactive status. Such appeals and cross appeals will be permanently withdrawn at such time that the Final Restructuring Order is no longer subject to administrative or judicial challenge.

In an appeal of a PUC order issued in May 1997, an intervenor brought an action asserting that the stranded cost recovery provisions of the Competition Act violated the Commerce Clause of the United States Constitution. On May 7, 1998, the Commonwealth Court of Pennsylvania unanimously rejected the claim. The intervenor petitioned the Supreme Court of Pennsylvania for allowance of appeal. On September 29, 1998, the Pennsylvania Supreme Court denied the petition. On December 28, 1998, the intervenor filed a petition for certiorari with the United States Supreme Court.

Limerick

Through 1997, the Company was recovering certain deferred Limerick costs. At December 31, 1997, the unamortized portion of these regulatory assets of $321 million was included as part of electric generation-related regulatory assets.

Under its electric tariffs and ECA, the Company was allowed to retain for shareholders any proceeds above the average energy cost for sales of 399 megawatts (MW) of near-term excess capacity and/or associated energy and to share in the benefits which resulted from the operation of both Limerick Units No. 1 and No. 2. The Company's ECA was discontinued at December 31, 1996. During 1996, the Company recorded as revenue net of fuel costs $82 million, as a result of the sale of the 399 MW of capacity and/or associated energy and the Company's share of Limerick energy savings.

Declaratory Accounting Order

Pursuant to a PUC Declaratory Order, effective October 1, 1996, the Company increased depreciation and amortization on assets associated with Limerick by $100 million per year and decreased depreciation and amortization on other Company assets by $10 million per year, for a net increase in depreciation and amortization of $90 million per year. At December 31, 1997, $90 million of depreciation and amortization that would have been recognized in 1998 was deferred as a regulatory asset since the Company's rates continued to be cost-based until January 1, 1999. During 1998 these amounts were amortized and recovered.

Energy Cost Adjustment (ECA)

Through December 31, 1996, the Company was subject to a PUC-established electric ECA which, in addition to reconciling fuel costs and revenues, incorporated a nuclear performance standard which allowed for financial bonuses or penalties depending on whether the Company's system nuclear capacity factor exceeded or fell below a specified range. For the year ended December 31, 1996 the Company recorded a bonus of $22 million.

4. Accounting Changes

The Company accounts for its electric transmission and distribution and gas operations in accordance with SFAS No. 71 which requires the Company to record the financial statement effects of the rate regulation to which the Company is subject. Use of SFAS No. 71 is applicable to the utility operations of the Company which meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable assumption that all costs will be recoverable from customers through rates. The Company believes that it is probable that regulatory assets associated with these operations will be recovered.

Effective December 31, 1997, the Company discontinued the application of SFAS No. 71 for its retail electric generation operations and adopted the provisions of SFAS No. 101 "Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71."

As required by SFAS No. 101, at December 31, 1997, the Company performed an impairment test of its electric generation assets pursuant to SFAS No. 121, on a plant specific basis and determined that $6.1 billion of its $7.1 billion of electric generation assets would be impaired as of December 31, 1998. The Company estimated the fair value for each of its electric generating units by determining its estimated future operating cash inflows and outflows. The net future cash flows for each electric generating plant were then compared to its net book value. For any electric generating plant with future undiscounted cash flows less than its book value, net cash flows were discounted using a discount rate commensurate with the risk of each electric generating plant. Since the Company's retail electric rates continued to be cost-based through January 1, 1999, $333 million representing depreciation expense on electric generation-related

assets in 1998 and $91 million representing amortization of [redacted]er regulatory assets in 1998 were reclassified to a regula[redacted]y asset and were amortized and recovered in 1998.

At December 31, 1997, the Company had total electric generation-related stranded costs of $8.4 billion, representing $5.8 billion of net stranded electric generation plant and $2.6 billion of electric generation-related regulatory assets. The original PUC restructuring order allowed the Company to recover $5.3 billion of its generation-related stranded costs from customers. This resulted in a net unrecoverable amount of $3.1 billion. Accordingly, the Company recorded an extraordinary charge at December 31, 1997 of $3.1 billion ($1.8 billion net of taxes) of electric generation-related stranded costs that will not be recovered from customers. The Final Restructuring Order did not change the amount of allowable stranded costs.

Effective December 31, 1997, the Company discontinued the application of SFAS No. 71 for its wholesale energy sales operations. Based on projections of the Company's retail load growth, the Company concluded all of its owned generation capacity would be necessary to meet its electric retail load. As a result, the discontinuance of SFAS No. 71 for its wholesale energy sales operations did not result in a charge against income.

5. Commitments and Contingencies

Capital Commitments

The Company estimates $440 million of capital expenditures [redacted]1999. Certain facilities under construction and to be con[redacted]ucted may require permits and licenses which the [redacted]ompany has no assurance will be granted. Capital expenditures do not include investments in joint ventures including investments related to the Company's strategy to expand its generation portfolio.

Nuclear Insurance

As of December 31, 1998, the Price-Anderson Act limited the liability of nuclear reactor owners to $9.8 billion for claims that could arise from a single incident. The limit is subject to change to account for the effects of inflation and changes in the number of licensed reactors. The Company carries the maximum available commercial insurance of $200 million and the remaining $9.6 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed up to $88 million per reactor per incident, payable at no more than $10 million per reactor per incident per year. This assessment is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose revenue raising measures on the nuclear industry to pay claims.

The Company carries property damage, decontamination and premature decommissioning insurance in the amount of its $2.75 billion proportionate share for each station loss resulting from damage to its nuclear plants. In the event of an accident, insurance proceeds must first be used for reac[redacted] stabilization and site decontamination. If the decision is [redacted]de to decommission the facility, a portion of the insurance proceeds will be allocated to a fund which the Company is required by the Nuclear Regulatory Commission (NRC) to maintain to provide for decommissioning the facility. The Company is unable to predict the timing of the availability of insurance proceeds to the Company for the Company's bondholders, and the amount of such proceeds which would be available. Under the terms of the various insurance agreements, the Company could be assessed up to $30 million for losses incurred at any plant insured by the insurance companies. The Company is self-insured to the extent that any losses may exceed the amount of insurance maintained. Such losses could have a material adverse effect on the Company's financial condition and results of operations.

The Company is a member of an industry mutual insurance company which provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. The Company's maximum share of any assessment is $10 million per year.

Nuclear Decommissioning and Spent Fuel Storage

The Company's current estimate of its nuclear facilities' decommissioning cost is $1.5 billion in 1997 dollars. Through 1998, this amount was being collected through electric rates over the life of each generating unit. Beginning in 1999, decommissioning costs will be recoverable through regulated rates. Under rates in effect through December 31, 1998, the Company collected and expensed approximately $20 million annually from customers which was accounted for as a component of depreciation expense and accumulated depreciation. At December 31,1998 and 1997, $336 and $294 million, respectively, were included in accumulated depreciation. In order to fund future decommissioning costs, at December 31, 1998 and 1997, the Company held $378 and $320 million, respectively, in trust accounts which are included as Investments in the Company's Consolidated Balance Sheets and include both net unrealized and realized gains. Net unrealized gains of $60 and $43 million were recognized as a Deferred Credit in the Company's Consolidated Balance Sheet at December 31, 1998 and 1997, respectively. The Company recognized net realized gains of $12, $11 and $10 million as Other Income in the Company's Consolidated Statement of Income for the years ended December 31, 1998, 1997 and 1996, respectively. The Company believes that the amounts being recovered from customers through regulated rates will be sufficient to fully fund the unrecorded portion of its decommissioning obligation.

In an Exposure Draft issued in 1996, the FASB proposed changes in the accounting for closure and removal costs of production facilities, including the recognition, measurement and classification of decommissioning costs for nuclear generating stations. The FASB has expanded the scope of the Exposure Draft to include closure or removal liabilities that are incurred at any time during the operating life of the related long-lived asset. The FASB has decided that it should proceed toward either a final Statement or a revised Exposure Draft. The timing of this project is still to be determined. If current electric utility industry accounting practices for decommissioning are changed, annual provisions for decommissioning could increase and the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation with recognition of an increase in the cost of a related regulatory asset.

Under the Nuclear Waste Policy Act of 1982 (NWPA), the U.S. Department of Energy (DOE) is required to begin taking possession of all spent nuclear fuel generated by the

Company's nuclear units for long-term storage by no later than 1998. Based on recent public pronouncements, it is not likely that a permanent disposal site will be available for the industry before 2015, at the earliest. In reaction to statements from the DOE that it was not legally obligated to begin to accept spent fuel in 1998, a group of utilities and state government agencies filed a lawsuit against the DOE which resulted in a decision by the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) in July 1996 that the DOE had an unequivocal obligation to begin to accept spent fuel in 1998. In accordance with the NWPA, the Company pays the DOE one mill ($.001) per kilowatthour of net nuclear generation for the cost of nuclear fuel long-term storage and disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. Because of inaction by the DOE following the D.C. Court of Appeals finding of the DOE's obligation to begin receiving spent fuel in 1998, a group of forty-two utility companies, including the Company, and forty-six state agencies, filed suit against the DOE seeking authorization to suspend further payments to the U.S. government under the NWPA and to deposit such payments into an escrow account until such time as the DOE takes effective action to meet its 1998 obligations. In November 1997, the D.C. Court of Appeals issued a decision in which it held that the DOE had not abided by its prior determination that the DOE has an unconditional obligation to begin disposal of spent nuclear fuel by January 31, 1998. The D.C. Court of Appeals also precluded the DOE from asserting that it was not required to begin receiving spent nuclear fuel because it had not yet prepared a permanent repository or an interim storage facility. The DOE and one of the utility companies filed Petitions for Reconsideration of the decision which were denied, as were petitions seeking U.S. Supreme Court review of the decision. In addition, the DOE is exploring other options to address delays in the waste acceptance schedule.

Peach Bottom has on-site facilities with capacity to store spent nuclear fuel discharged from the units through 2000 for Unit No. 2 and 2001 for Unit No. 3. Life-of-plant storage capacity will be provided by on-site dry cask storage facilities, the construction of which began in 1998. Limerick has on-site facilities with capacity to store spent nuclear fuel to 2007. Salem has on-site facilities with spent fuel storage capacity through 2008 for Unit No. 1 and 2012 for Unit No. 2.

Energy Commitments

The Company's electric utility operations include the wholesale marketing of electricity. The Company utilized certain types of fixed-price contracts and other risk management instruments in connection with its wholesale marketing operations. These contracts include long-term contracts which commit the Company to purchase or sell energy at fixed prices in the future (i.e. fixed-price forward purchase and sales contracts), and short-term bilateral swaps and options contracted for in the over-the-counter market. Under some of these contracts, the Company may purchase at its option additional power as needed. The use of the foregoing types of contracts is so that the Company may manage and hedge its retail and wholesale commitments in coordination with the economic dispatch of the Company's installed capacity.

At December 31,1998, the Company had long-term commitments relating to the purchase from unaffiliated utilities and others of energy associated with 632 MW of capacity in 1999, with 2,054 MW of capacity during the period 2000 through 2002 and with 2,431 MW of capacity thereafter. During 1998, purchases under long-term commitments resulted in expenditures of $170 million. As of December 31, 1998, these purchase commitments result in obligations of approximately $121 million for 1999, $526 million for 2000 through 2002 and $805 million thereafter. These purchases will be utilized through a combination of retail sales to customers, long-term sales to other utilities and open market sales.

At December 31, 1998, the Company had entered into long-term agreements with unaffiliated utilities to sell energy associated with 5,094 MW of capacity, of which 1,030 MW of these agreements are for 1999, 2,202 MW are for 2000 through 2002 and the remaining 1,862 MW extend through 2009.

At December 31, 1998, the Company had entered into long-term agreements with unaffiliated utilities to purchase transmission rights. These purchase commitments result in obligations of approximately $21 million in 1999, $19 million in 2000 and $9 million per year in 2001 through 2003.

Environmental Issues

The Company's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws. Additionally, under federal and state environmental laws, the Company is generally liable for the costs of remediating environmental contamination of property now or formerly owned by the Company and of property contaminated by hazardous substances generated by the Company. The Company owns or leases a number of real estate parcels, including parcels on which its operations or the operations of others may have resulted in contamination by substances which are considered hazardous under environmental laws. The Company is currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

The Company has identified 28 sites where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. The Company is presently engaged in performing various levels of activities at these sites, including initial evaluation to determine the existence and nature of the contamination, detailed evaluation to determine the extent of the contamination and the necessity and possible methods of remediation, and implementation of remediation. The Pennsylvania Department of Environmental Protection has approved the Company's clean up of three sites. Eight other sites are currently under some degree of active study and/or remediation.

As of December 31, 1998 and 1997, the Company had accrued $60 and $63 million, respectively, for environmental investigation and remediation costs, including $33 and $35 million, respectively, for MGP investigation and remediation, that currently can be reasonably estimated. The Company cannot reasonably estimate whether it will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Company, environmental agencies or others, or whether such costs will be recoverable from third parties.

Litigation

Grays Ferry Cogeneration Partnership

On April 9, 1998, Grays Ferry Cogeneration Partnership (Grays Ferry), two of three partners of Grays Ferry and Trigen-Philadelphia Energy Corporation, filed a complaint in Philadelphia County of Common Pleas against the Company for specific performance, breach of contract, fraud and breach of implied covenant of good faith and fair dealing, conversion, unjust enrichment, breach of fiduciary duties and tortious interference with respect to two power purchase agreements (PPAs) that the Company had entered into with Grays Ferry. The plaintiff seeks specific performance, damages in excess of $200 million and punitive damages. A preliminary injunction was entered against the Company on May 5, 1998, enjoining the Company from terminating the PPAs. On May 29, 1998, Westinghouse Power Generation filed a complaint in the Philadelphia Court of Common Pleas against the Company for tortious interference with two alleged contracts that Westinghouse has with Grays Ferry. On September 4, 1998, The Chase Manhattan Bank, as agent for a syndicate of banks that are lenders to Grays Ferry, filed a complaint against the Company alleging tortious interference by the Company in the credit agreements between Grays Ferry and the banks and breach of contract of a letter agreement between the Company and the banks. The Company cannot predict the outcome of these matters.

Cajun Electric Power Cooperative, Inc.

On May 27, 1998, the United States Department of Justice, on behalf of the Rural Utilities Service and the Chapter 11 Trustee for the Cajun Electric Power Cooperative, Inc. (Cajun), filed an action claiming breach of contract against the Company in the United States District Court for the Middle District of Louisiana arising out of the Company's termination of the contract to purchase Cajun's interest in the River Bend nuclear power plant. This action seeks $67 million in damages. The Company cannot predict the outcome of this matter.

The Company is involved in various other litigation matters. The ultimate outcome of such matters, while uncertain, is not expected to have a material adverse effect on the Company's financial condition or results of operations.

6. Retirement Benefits

The Company and its subsidiaries have a defined benefit pension plan and postretirement benefit plans applicable to essentially all employees. The following provides a reconciliation of benefit obligations, plan assets and funded status of the plans.

Thousands of Dollars	Pension Benefits		Other Postretirement Benefits	
	1998	1997	**1998**	1997
Change in Benefit Obligation				
Net benefit obligation at beginning of year	**$ 2,141,040**	$ 1,982,915	**$ 779,231**	$ 662,701
Service cost	**30,167**	25,368	**18,375**	14,401
Interest cost	**153,644**	150,057	**53,924**	54,149
Plan participants' contributions	**—**	—	**397**	—
Plan amendments	**—**	(3,052)	**—**	—
Actuarial (gain)/loss	**143,274**	129,148	**(8,260)**	85,452
Curtailments	**(73,330)**	—	**10,403**	—
Settlements	**(46,541)**	—	**—**	—
Special termination benefits	**114,182**	—	**29,712**	—
Gross benefits paid	**(152,850)**	(143,396)	**(36,011)**	(37,472)
Net benefit obligation at end of year	**$ 2,309,586**	$ 2,141,040	**$ 847,771**	$ 779,231
Change in Plan Assets				
Fair value of plan assets at beginning of year	**$ 2,538,039**	$ 2,302,935	**$ 178,045**	$ 126,661
Actual return on plan assets	**343,754**	377,803	**23,535**	22,691
Employer contributions	**16,404**	697	**57,319**	66,165
Plan participants' contributions	**—**	—	**397**	—
Gross benefits paid	**(152,850)**	(143,396)	**(36,011)**	(37,472)
Fair value of plan assets at end of year	**$ 2,745,347**	$ 2,538,039	**$ 223,285**	$ 178,045
Funded status at end of year	**$ 435,761**	$ 396,999	**$ (624,486)**	$ (601,186)
Unrecognized net actuarial (gain)/loss	**(659,480)**	(649,903)	**37,617**	53,110
Unrecognized prior service cost	**65,419**	83,188	**—**	—
Unrecognized net transition obligation(asset)	**(30,512)**	(35,713)	**165,786**	223,226
Net amount recognized at end of year	**$ (188,812)**	$ (205,429)	**$ (421,083)**	$ (324,850)
Amounts recognized in the consolidated balance sheet consist of:				
Prepaid benefit cost	**$ 30,462**	$ 6,167	**$ N/A**	$ N/A
Accrued benefit cost	**(219,274)**	(211,596)	**(421,083)**	(324,850)
Net amount recognized at end of year	**$ (188,812)**	$ (205,429)	**$ (421,083)**	$ (324,850)

	Pension Benefits			Other Postretirement Benefits		
	1998	1997	1996	**1998**	1997	19
Weighted-average assumptions as of December 31						
Discount rate	**7.00%**	7.25%	7.75%	**7.00%**	7.25%	7.75%
Expected return on plan assets	**9.50%**	9.50%	9.50%	**8.00%**	8.00%	8.00%
Rate of compensation increase	**5.00%**	5.00%	5.00%	**5.00%**	5.00%	5.00%
Health care cost trend on covered charges	**N/A**	N/A	N/A	**6.5% decreasing to ultimate trend of 5.0% in 2002**	7.0% decreasing to ultimate trend of 5.0% in 2002	8.0% decreasing to ultimate trend 5.0% in 2002
Components of net periodic benefit cost						
Service cost	**$ 30,167**	$ 25,368	$ 27,627	**$ 18,375**	$ 14,401	$ 11,855
Interest cost	**153,644**	150,057	145,570	**53,924**	54,149	48,524
Expected return on assets	**(209,976)**	(182,866)	(171,207)	**(13,243)**	(9,984)	(3,937)
Amortization of:						
Transition obligation (asset)	**(4,538)**	(4,538)	(4,538)	**14,882**	14,882	14,882
Prior service cost	**6,441**	6,441	5,114	**—**	—	—
Actuarial (gain)loss	**(7,028)**	(3,898)	248	**—**	—	—
Curtailment charge (credit)	**(62,002)**	—	—	**52,961**	—	—
Settlement charge (credit)	**(13,439)**	—	—	**—**	—	—
Net periodic benefit cost	**$ (106,731)**	$ (9,436)	$ 2,814	**$ 126,899**	$ 73,448	$ 71,324
Special termination benefit charge(credit)	**$ 114,182**	$ —	$ —	**$ 29,712**	$ —	$ —

Sensitivity of retiree welfare results

Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ 10,432
on postretirement benefit obligation	$ 90,490
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (8,460)
on postretirement benefit obligation	$ (75,599)

Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plans.

During 1998, costs were recognized for special termination benefits in connection with the retirement incentives and enhanced severance benefits provided under the Company's Workforce Reduction Program.

The Company provides certain health care and life insurance benefits for retired employees. Company employees become eligible for these benefits if they retire from the Company with ten years of service. These benefits and similar benefits for active employees are provided by an insurance company whose premiums are based upon the benefits paid during the year.

The Company sponsors a qualifying savings plan covering all employees. Contributions made by participating employees are matched based on a specified percentage of employee contribution up to 4% of the employees' pay base. The cost of the Company's matching contribution to the savings plan totaled $7 million, $7 million and $3 million in 1998, 1997 and 1996, respectively.

7. Accounts Receivable

Accounts receivable at December 31, 1998 and 1997 included unbilled operating revenues of $142 and $135 million, respectively. The allowance for uncollectible accounts at December 31, 1998 and 1997 was $20 and $32 million, respectively.

The Company is party to an agreement with a financial institution under which it can sell or finance with limited recourse an undivided interest, adjusted daily, in up to $425 million of designated accounts receivable until November 2000. At December 31, 1998, the Company had sold a $425 million interest in accounts receivable, consisting of a $358 million interest in accounts receivable which the Company accounts for as a sale and a $67 million interest in special agreement accounts receivable which were accounted for as a long-term note payable (see note 12). The Company retains the servicing responsibility for these receivables. The agreement requires the Company to maintain the $425 million interest, which, if not met, requires the Company to deposit cash in order to satisfy such requirements. At December 31, 1998, the Company did not meet this requirement and was required to make a deposit of $7 million.

8. Common Stock

At December 31, 1998 and 1997, common stock without par value consisted of 500,000,000 shares authorized and 224,684,306 and 222,546,562 shares outstanding, respectively. At December 31, 1998, there were 5,800,841 shares reserved for issuance under the Company's Dividend Reinvestment and Stock Purchase Plan.

Stock Repurchase

During 1997, the Company's Board of Directors authorized the repurchase of up to 25 million shares of its common stock from time to time through open-market, privately negotiated and/or other types of transactions in conformity with the rules of the Securities and Exchange Commission.

Pursuant to these authorizations, the Company has entered into forward purchase agreements to be settled from time to time, at the Company's election, on either a physical, net share or net cash basis. The amount at which these agreements can be settled is dependent principally upon the market price of the Company's common stock as compared to the forward purchase price per share and the number of shares to be settled. If these agreements had been settled on a net share basis at December 31, 1998, based on the closing price of the Company's common stock on that date, the Company would have received approximately 4.6 million shares of Company common stock.

Stock Option Plans

The Company maintains a Long-Term Incentive Plan (LTIP) for certain full-time salaried employees of the Company. The types of long-term incentive awards which have been granted under the LTIP are non-qualified options to purchase shares of the Company's common stock and shares of restricted common stock. In 1998, the Company initiated a Broad-based Incentive Program and awarded non-qualified options to all employees except those in electric transmission and distribution system and gas operations. The Company uses the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." If the Company elected to account for the LTIP based on SFAS No. 123, earnings applicable to common stock and earnings per average common share would have been changed to the pro forma amounts as follows:

		1998	1997
		Thousands of Dollars	
Earnings (Loss) applicable to common stock	As reported	**$ 499,615**	$ (1,513,910)
	Pro forma	**$ 493,696**	$ (1,515,895)
Earnings (Loss) per average common share (Dollars)	As reported	**$ 2.24**	$ (6.80)
	Pro forma	**$ 2.20**	$ (6.81)

Options granted under the LTIP and the Broad-based Incentive Program become exercisable upon attainment of a target share value and/or time. All options expire 10 years from the date of grant. Information with respect to the LTIP and the Broad-based Incentive Program at December 31, 1998 and changes for the three years then ended, is as follows:

	Shares 1998	Weighted Average Exercise Price (per share) 1998	Shares 1997	Weighted Average Exercise Price (per share) 1997	Shares 1996	Weighted Average Exercise Price (per share) 1996
Balance at January 1	**3,816,794**	**$ 26.14**	2,961,194	$ 26.68	2,591,765	$ 26.16
Options granted	**2,933,540**	**27.74**	1,139,000	22.49	786,500	28.12
Options exercised	**(2,130,744)**	**23.86**	—	—	(369,871)	25.07
Options cancelled	**(91,000)**	**24.82**	(283,400)	24.96	(47,200)	29.36
Balance at December 31	**4,528,590**	**27.71**	3,816,794	26.14	2,961,194	26.68
Exercisable at December 31	**3,462,550**	**23.91**	**2,800,794**	26.65	**2,192,694**	26.17
Weighted average fair value of options granted during year		**$ 3.43**		**$ 2.97**		**$ 2.78**

The fair value of each option is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used for grants in 1998, 1997 and 1996, respectively:

	1998	1997	1996
Dividend yield	**6.8%**	6.2%	6.2%
Expected volatility	**21.4%**	19.5%	16.6%
Risk-free interest rate	**5.5%**	6.4%	5.5%
Expected life (years)	**9.5**	5	5

At December 31, 1998, the option groups outstanding, based on ranges of exercise prices, were as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted-Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$15.75 - $20.00	899,700	8.71	$ 19.60	899,700	$ 19.60
$20.01 - $25.00	1,019,750	8.41	22.15	1,004,750	22.18
$25.01 - $30.00	1,510,600	5.76	27.38	1,510,600	27.38
$30.01 - $35.00	78,500	9.43	32.97	47,500	31.98
$35.01 - $50.00	1,020,040	9.87	40.48	—	—
Total	4,528,590			3,462,550	

The Company issued 7,000 and 4,475 shares of restricted common stock during 1998 and 1997, respectively. Vesting in the restricted common stock awards is over a period not to exceed 10 years from the grant date. The compensation cost associated with these awards is amortized to expense over the vesting period. Compensation cost associated with these awards is immaterial.

9. Earnings Per Share

Diluted earnings per average common share is calculated by dividing earnings applicable to common stock by the weighted average shares of common stock outstanding including stock options outstanding under the Company's stock option plans considered to be common stock equivalents. The following table shows the effect of these stock options on the weighted average number of shares outstanding used in calculating diluted earnings per average common share:

	1998	1997	1996
Average Common Shares Outstanding	**223,219,000**	222,543,000	222,490,000
Assumed Conversion of Stock Options	**685,000**	—	—
Potential Average Dilutive Common Shares Outstanding	**223,904,000**	222,543,000	222,490,000

10. Preferred and Preference Stock

At December 31, 1998 and 1997, Series Preference Stock consisted of 100,000,000 shares authorized, of which no shares were outstanding. At December 31, 1998 and 1997, cumulative Preferred Stock, no par value, consisted of 15,000,000 shares authorized.

Series of Preferred Stock	Current Redemption Price(a)	Shares Outstanding 1998	Shares Outstanding 1997	Amount Thousands of Dollars 1998	Amount Thousands of Dollars 1997
Series (without mandatory redemption)					
$4.68	104.00	**150,000**	150,000	**$ 15,000**	$ 15,000
$4.40	112.50	**274,720**	274,720	**27,472**	27,472
$4.30	112.00	**150,000**	150,000	**15,000**	15,000
$3.80	106.00	**300,000**	300,000	**30,000**	30,000
$7.48	(b)	**500,000**	500,000	**50,000**	50,000
		1,374,720	1,374,720	**137,472**	137,472
Series (with mandatory redemption)					
$6.12	(c)	**927,000**	927,000	**92,700**	92,700
Total preferred stock		**2,301,720**	2,301,720	**$ 230,172**	$ 230,172

(a) Redeemable, at the option of the Company, at the indicated dollar amounts per share, plus accrued dividends.
(b) None of the shares of this series are subject to redemption prior to April 1, 2003.
(c) Annual sinking fund requirements in 1999 - 2003 are $18,540,000. None of the shares of this series are subject to redemption prior to August 1, 1999.

11. Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership (COMRPS)

At December 31, 1998 and 1997, PECO Energy Capital, L.P. (Partnership), a Delaware limited partnership of which a wholly owned subsidiary of the Company is the sole general partner, had outstanding A, C and D series of COMRPS with liquidation values of $25 (A and C) and $1,000 (D) per security. Each series is supported by the Company's deferrable interest subordinated debentures, held by the Partnership, which bear interest at rates equal to the distribution rates on the related series of COMRPS. The interest expense on the debentures is included in Other Income and Deductions in the Consolidated Statements of Income and is deductible for tax purposes.

At December 31,	Mandatory Redemption Date	Distribution Rate	Trust Receipts Outstanding 1998	Trust Receipts Outstanding 1997	Amount *Thousands of Dollars* 1998	Amount *Thousands of Dollars* 1997
Series						
A	2043	9.00%	**8,850,000**	8,850,000	**$ 221,250**	$ 221,250
B (a)	2025	8.72%	**—**	3,124,183	**—**	80,835
C (b)	2037	8.00%	**2,000,000**	2,000,000	**50,000**	50,000
D (c)	2028	7.38%	**78,105**	—	**78,105**	—
Total			**10,928,105**	13,974,183	**$ 349,355**	$ 352,085

(a) On May 15, 1998, PECO Energy Capital Trust I redeemed all outstanding Trust Receipts, each representing an 8.72% Cumulative Monthly Income Preferred Security, Series B of PECO Energy Capital, L.P.
(b) Ownership of this series is evidenced by Trust Receipts, each representing an 8.00% COMRPS, Series C, representing limited partnership interests. The Trust Receipts were issued by PECO Energy Capital Trust II, the sole assets of which are 8.00% COMRPS, Series C. Each holder of Trust Receipts is entitled to withdraw the corresponding number of 8.00% COMRPS, Series C from the Trust in exchange for the Trust Receipts so held.
(c) Ownership of this series is evidenced by Trust Receipts, each representing an 7.38% COMRPS, Series D, representing limited partnership interests. The Trust Receipts were issued by PECO Energy Capital Trust III, the sole assets of which are 7.38% COMRPS, Series D. Each holder of Trust Receipts is entitled to withdraw the corresponding number of 7.38% COMRPS, Series D from the Trust in exchange for the Trust Receipts so held. This Series was issued on April 6, 1998.

12. Long-Term Debt

At December 31,	Series	Due	1998	1997
			Thousands of Dollars	
First and refunding mortgage bonds (a)	5 3/8 %	1998	**$ —**	$ 225,000
	7 1/2%-9 1/4%	1999	**325,000**	325,000
	5 5/8%-7 3/8%	2001	**330,000**	330,000
	7 1/8%-8%	2002	**500,000**	500,000
	6 1/2%-6 5/8%	2003	**450,000**	450,000
	6 3/8%-10 1/4 %	2004-2008	**111,562**	115,625
	(b)	2009-2013	**154,200**	154,200
	6 5/8%-8 3/4%	2019-2024	**1,082,130**	1,607,130
Total first and refunding mortgage bonds			**2,952,892**	3,706,955
Notes payable			**15,930**	15,574
Pollution control notes	(c)		**212,705**	212,705
Medium-term notes	(d)		**50,000**	62,400
Note Payable - accounts receivable agreement	(e)		**66,837**	128,999
Unamortized debt discount and premium, net			**(17,249)**	(26,405)
Total long-term debt			**3,281,115**	4,100,228
Due within one year	(f)		**361,523**	247,087
Long-term debt included in capitalization	(g)		**$ 2,919,592**	$ 3,853,141

(a) Utility plant is subject to the lien of the Company's mortgage.

(b) Floating rates, which were an average annual interest rate of 3.13% at December 31, 1998.

(c) Floating rates, which were an average annual interest rate of 3.32% at December 31, 1998.

(d) Medium-term notes collateralized by mortgage bonds. The average annual interest rate was 9.09% at December 31, 1998.

(e) See note 7.

(f) Long-term debt maturities, including mandatory sinking fund requirements, in the period 1999-2003 are as follows: 1999 - $361,523,000; 2000 - $74,255,500; 2001 - $337,431,500; 2002 - $507,436,500; 2003 - $406,534,500.

(g) The annualized interest on long-term debt at December 31, 1998, was $222 million, of which $210 million was associated with mortgage bonds and $12 million was associated with other long-term debt.

In the fourth quarter of 1998, the Company redeemed $525 million of its First Mortgage Bonds consisting of: $150 million of its 8 3/4% series due 2022, $125 million of its 8 5/8% series due 2022 and $250 million of its 8 1/4% series due 2022 at redemption prices of 105.75, 105.20 and 104.85 plus interest, respectively. As a result, the Company recognized an extraordinary charge of $34 million ($20 million net of income taxes). The extraordinary charge consisted primarily of premiums and the write-off of deferred charges.

13. Short-Term Debt

	1998	1997	1996
		Thousands of Dollars	
Average borrowings	**$ 209,261**	$ 248,111	$ 198,090
Average interest rates, computed on daily basis	**5.83%**	5.83%	5.64%
Maximum borrowings outstanding	**$ 525,000**	$ 464,500	$ 369,500
Average interest rates, at December 31	**6.17%**	6.74%	6.90%

The Company has a $400 million one-year term loan agreement with a group of banks, which expires on November 30, 1999. At December 31, 1998, $400 million of short-term debt was outstanding under this term loan agreement.

The Company has a $900 million unsecured revolving credit facility with a group of banks. The credit facility consists of a $450 million 364-day credit agreement and a $450 million three-year credit agreement. The Company uses the credit facility principally to support its $600 million commercial paper program. There was no debt outstanding under this credit facility at December 31, 1998. At December 31, 1998, $125 million of commercial paper was outstanding. At December 31, 1998, the Company had available formal and informal lines of credit with banks aggregating $100 million.

14. Income Taxes

Income tax expense (benefit) is comprised of the following components:

For the Years Ended December 31,	1998	1997	1996
			Thousands of Dollars
Included in operations:			
Federal			
Current	**$ 358,051**	$ 251,509	$ 126,471
Deferred	**(109,211)**	(11,378)	154,564
Investment tax credit, net	**(18,066)**	(18,201)	(15,979)
State			
Current	**95,309**	76,689	62,839
Deferred	**(6,429)**	(5,850)	12,206
	319,654	292,769	340,101
Included in extraordinary item:			
Federal			
Current	**(10,583)**	(123)	—
Deferred	**—**	(987,234)	—
State			
Current	**(3,174)**	(29)	—
Deferred	**—**	(303,575)	—
	(13,757)	(1,290,961)	—
Total	**$ 305,897**	$ (998,192)	$ 340,101

The total income tax provisions, excluding the extraordinary item, differed from amounts computed by applying the federal statutory tax rate to pre-tax income as follows:

	1998	1997	1996
			Thousands of Dollars
Net Income	**$ 532,378**	$ 336,558	$ 517,205
Total income tax provisions	**319,654**	292,769	340,101
Income before income taxes	**$ 852,032**	$ 629,327	$ 857,306
Income taxes on above at federal statutory rate of 35%	**$ 298,211**	$ 220,264	$ 300,057
Increase (decrease) due to:			
Property basis differences	**(10,262)**	40,828	9,903
State income taxes, net of federal income tax benefit	**57,582**	46,046	48,779
Amortization of investment tax credit	**(18,066)**	(18,201)	(15,979)
Prior period income taxes	**(12,951)**	(2,985)	(1,707)
Other, net	**5,140**	6,817	(952)
Total income tax provisions	**$ 319,654**	$ 292,769	$ 340,101
Effective income tax rate	**37.5%**	46.5%	39.7%

Provisions for deferred income taxes consist of the tax effects of the following temporary differences:

	1998	1997	1996
			Thousands of Dollars
Deferred generation charges recoverable	**$ (174,787)**	$ —	$ —
Depreciation and amortization	**140,448**	57,530	42,385
Deferred energy costs	**(2,491)**	2,256	27,374
Retirement and separation programs	**(51,146)**	(12,734)	19,746
Incremental nuclear outage costs	**(7,434)**	(981)	2,440
Uncollectible accounts	**4,764**	(1,710)	(2,805)
Reacquired debt	**(5,026)**	(8,607)	(9,578)
Unbilled revenue	**3,579**	(5,110)	3,910
Environmental clean-up costs	**(3,574)**	(15,121)	(714)
Obsolete inventory	**4,206**	(7,074)	5,829
Limerick plant disallowances and phase-in plan	**—**	(747)	(747)
AMT credits	**(42,067)**	—	83,010
Other nuclear operating costs	**9,926**	(9,892)	—
Other	**7,962**	(15,038)	(4,080)
Subtotal	**(115,640)**	(17,228)	166,770
Extraordinary item	**—**	(1,290,809)	—
Total	**$ (115,640)**	$ (1,308,037)	$ 166,770

The tax effect of temporary differences giving rise to the Company's net deferred tax liability as of December 31, 1998 and 1997 is as follows:

	Liability or (Asset)	
	1998	1997
		Thousands of Dollars
Nature of temporary difference:		
Plant basis difference	**$ 2,653,760**	$ 2,620,254
Deferred investment tax credit	**299,999**	318,065
Deferred debt refinancing costs	**37,575**	111,651
Other, net	**(300,375)**	(249,167)
Deferred income taxes (net) on the balance sheet	**$ 2,690,959**	$ 2,800,803

The net deferred tax liability shown above as of December 31, 1998 and 1997 was comprised of $3,123 and $3,153 million of deferred tax liabilities, and $432 and $352 million of deferred tax assets, respectively.

In accordance with SFAS No. 71, the Company recorded a recoverable deferred income tax asset of $614 and $586 million at December 31,1998 and 1997, respectively. These balances are applicable only to regulated assets, due to the discontinuance of SFAS No. 71 for the Company's electric generation operations. These recoverable deferred income taxes include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the PUC, as well as the revenue impacts thereon, and assume recovery of these costs in future rates.

The Internal Revenue Service (IRS) has completed and settled its examinations of the Company's federal income tax returns through 1990 which resulted in a net increase of $11 million in credits available for carry forward. The 1991 through 1993 federal income tax returns have been examined and the Company and the IRS are in the process of settling the audit which will not have an adverse impact on financial condition or results of operations of the Company. The years 1994 through 1996 are currently being examined by the IRS.

15. Taxes, Other Than Income - Operating

For the Years Ended December 31,	1998	1997	1996
			Thousands of Dollars
Gross receipts	**$ 155,663**	$ 163,552	$ 160,246
Capital stock	**43,754**	48,085	41,972
Real estate	**51,313**	69,597	69,185
Payroll	**30,068**	25,976	27,585
Other	**(1,283)**	2,881	558
Total	**$ 279,515**	$ 310,091	$ 299,546

16. Leases

Leased property included in utility plant was as follows:

At December 31,	1998	1997
		Thousands of Dollars
Nuclear fuel	**$ 523,325**	$ 521,921
Electric plant	**2,321**	2,321
Gross leased property	**525,646**	524,242
Accumulated amortization	**(371,338)**	(348,309)
Net leased property	**$ 154,308**	$ 175,933

Nuclear fuel is amortized as the fuel is consumed. Amortization of leased property totaled $60, $39 and $31 million for the years ended December 31, 1998, 1997 and 1996, respectively. Other operating expenses included interest on capital lease obligations of $9 million in 1998, 1997 and 1996, respectively.

Minimum future lease payments as of December 31, 1998 were:

For the Years Ending December 31,	Capital Leases	Operating Leases	Total
			Thousands of Dollars
1999	$ 69,026	$ 48,806	$ 117,832
2000	65,714	45,457	111,171
2001	32,439	42,850	75,289
2002	92	42,056	42,148
2003	92	49,386	49,478
Remaining years	721	511,164	511,885
Total minimum future lease payments	$ 168,084	$ 739,719	$ 907,803
Imputed interest (rates ranging from 6.5% to 17.0%)	(13,776)		
Present value of net minimum future lease payments	$ 154,308		

Rental expense under operating leases totaled $69 million in 1998 and $74 million in 1997 and 1996, respectively.

17. Jointly Owned Electric Utility Plant

The Company's ownership interests in jointly owned electric utility plant at December 31, 1998, were as follows:

	Production Plants				Transmission and Other Plant
	Peach Bottom	Salem	Keystone	Conemaugh	
Operator	PECO Energy Company	Public Service Electric and Gas Company	GPU Generating Corp.	GPU Generating Corp.	Various Companies
Participating interest	42.49%	42.59%	20.99%	20.72%	21% to 43%
Company's share *(Thousands of Dollars)*					
Utility plant	$ 347,001	$ 20,026	$ 118,256	$ 190,672	$ 82,078
Accumulated depreciation	183,383	12,929	73,644	91,052	32,638
Construction work in progress	22,586	1,632	1,770	3,865	1,300

The Company's participating interests are financed with Company funds and, when placed in service, all operations are accounted for as if such participating interests were wholly owned facilities.

18. Cash and Cash Equivalents

For purposes of the Statements of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. The following disclosures supplement the accompanying Statements of Cash Flows:

	1998	1997	1996
			Thousands of Dollars
Cash paid during the year:			
Interest (net of amount capitalized)	$ **384,932**	$ 405,838	$ 415,063
Income taxes (net of refunds)	**346,539**	345,232	251,554
Noncash investing and financing:			
Capital lease obligations incurred	**38,307**	32,909	33,063

19. Investments

At December 31,	1998	1997
		Thousands of Dollars
Trust accounts for decommissioning nuclear plants	**$ 377,970**	$ 320,442
Telecommunications ventures	**48,391**	85,601
Energy services and other ventures	**39,359**	65,578
Nonutility property	**40,456**	24,697
Other	**44,728**	19,517
Total	**$ 550,904**	$ 515,835

20. Financial Instruments

Fair values of financial instruments, including liabilities, are estimated based on quoted market prices for the same or similar issues. The carrying amounts and fair values of the Company's financial instruments as of December 31, 1998 and 1997 were as follows:

Thousands of Dollars	1998		1997	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Non-derivatives:				
Assets				
Cash and temporary cash investments	**$ 48,083**	**$ 48,083**	$ 33,404	$ 33,404
Trust accounts for decommissioning nuclear plants	**377,970**	**377,970**	320,442	320,442
Liabilities				
Long-term debt (including amounts due within one year)	**3,281,115**	**3,404,250**	4,100,228	4,210,885
Derivatives:				
Treasure forwards	**—**	**(300)**	—	—
Forward interest rate swaps	**—**	**(4,400)**	—	—

ancial instruments which potentially subject the Company concentrations of credit risk consist principally of temporary cash investments and customer accounts receivable. The Company places its temporary cash investments with high-credit quality financial institutions. At times, such investments may be in excess of the Federal Deposit Insurance Corporation limit. Concentrations of credit risk with respect to customer accounts receivable are limited due to the Company's large number of customers and their dispersion across many industries.

The fair value of derivatives generally reflects the estimated amounts that the Company would receive or pay to terminate the contracts at the reporting date, thereby taking into account the current unrealized gains or losses of open contracts. Dealer quotes are available for all of the Company's derivatives.

The anticipated issuance of Transition Bonds significantly exposes the Company to market risks of changes in interest rates. Derivative financial instruments are used by the Company to reduce these risks.

The Company has entered into treasury forwards in an aggregate notional amount of $4 billion with an average interest rate of 4.71%. The Company has entered into forward starting interest rate swaps in the aggregate notional amount of $713 million with an average interest rate of 5.72%. The notional amount of derivatives do not represent amounts that are exchanged by the parties and, thus, are not a measure of the Company's exposure. The amounts exchanged are calculated on the basis of the notional or contract amounts, as well as on the other terms of the derivatives, which relate to interest rates and the volatility of these rates.

The Company would be exposed to credit-related losses in the event of non-performance by the counterparties that issued the derivative instruments. The Company does not expect that counterparties to the interest rate swaps and treasury forwards will fail to meet these obligations, given their high credit ratings. The credit exposure of derivatives contracts is represented by the fair value of contracts at the reporting date. The Company's interest-rate swaps are documented under master agreements. Among other things, these agreements provide for a maximum credit exposure for both parties. Payments are required by the appropriate party when the maximum limit is reached. The same maximum credit exposure applies to the treasury forwards.

21. Early Retirement and Separation Program

In April 1998, the Board of Directors authorized the implementation of a retirement incentive program and an enhanced severance benefit program. The retirement incentive program allowed employees age 50 and older, who have been designated as excess or who are in job classifications facing reduction, to retire from the Company. The enhanced severance benefit program provided non-retiring excess employees with fewer than ten years of service benefits equal to two weeks pay per year of service. Non-retiring excess employees with more than ten years of service receive benefits equal to three weeks pay per year of service.

Through its Cost Competitiveness Review (CCR), the Company identified 1,157 employees across the Company who were considered excess or were in job classifications facing reduction. Of the 1,157 employees, 711 were eligible for and agreed to take the retirement incentive program. The remaining employees are eligible for the enhanced severance benefit program. The Company has eliminated approximately 422 positions as of December 31, 1998 through both attrition and the early retirement and severance program. The Company expects an additional 735 positions to be eliminated during 1999 and 2000.

The Company recorded an early retirement and separation program charge to earnings of $125 million ($74 million, net of income taxes) in the fourth quarter of 1998 to recognize costs related to the CCR workforce reduction program. This charge consisted of the following: $121 million for the actuarially determined pension and other postretirement benefits costs and $4 million for outplacement services costs and the continuation of benefits for one year. Approximately $0.8 million of the $125 million charge was related to the Company's non-utility operations and accordingly was recorded in Other Income and Deductions. All cash payments related to the early retirement and severance program are expected to be funded through the assets of the Company's Service Annuity Plan.

22. Other Income and Deductions

Settlement of Salem Litigation

On December 31, 1997, the Company received $70 million pursuant to the May 1997 settlement agreement with Public Service Electric and Gas Company resolving a suit filed by the Company concerning the shutdown of Salem. During the second quarter of 1997, the Company recorded $70 million ($41 million net of income taxes) as Other Income.

Ventures

The Company periodically reviews its investments to determine that they are properly valued in its financial statements. Other Income and Deductions reflects write-offs of these investments of $10 million and $20 million in 1998 and 1997, respectively.

23. Regulatory Assets and Liabilities

At December 31, 1998 and 1997, the Company had deferred the following regulatory assets on the Consolidated Balance Sheet:

	1998	1997
	Thousands of Dollars	
Competitive transition charge	**$ 5,274,624**	$ 5,274,624
Recoverable deferred income taxes (see note 14)	**614,445**	585,661
Deferred generation costs recoverable in current rates	**—**	424,497
Loss on reacquired debt	**77,165**	83,918
Compensated absences	**4,289**	3,881
Deferred energy costs	**29,847**	35,665
Non-pension postretirement benefits	**90,915**	97,409
Total	**$ 6,091,285**	$ 6,505,655

24. Quarterly Data (Unaudited)

The data shown below include all adjustments which the Company considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income (Loss)	
Millions of Dollars	**1998**	1997	**1998**	1997	**1998**	1997
Quarter ended						
March 31	**$ 1,173**	$ 1,163	**$ 285**	$ 302	**$ 114**	$ 113
June 30	**1,207**	1,032	**362**	250	**151**	123
September 30	**1,774**	1,278	**546**	388	**274**	158
December 31	**1,056**	1,145	**90**	66	**(26)**	(1,891)

	Earnings Applicable to Common Stock		Average Shares Outstanding		Earnings Per Average Share	
Millions of Dollars (except per share data)	**1998**	1997	**1998**	1997	**1998**	199
Quarter ended						
March 31	**$ 110**	$ 109	**222.5**	222.5	**$ 0.50**	$ 0.49
June 30	**148**	118	**222.7**	222.5	**0.66**	0.53
September 30	**270**	154	**223.1**	222.5	**1.21**	0.69
December 31	**(28)**	(1,895)	**224.5**	222.5	**(0.13)**	(8.51)

The increase in 1998 second quarter results was primarily due to increased operating revenues net of related fuel costs. Revenues from wholesale sales increased significantly compared to 1997. Second quarter 1998 earnings also benefited from the full return to service of Salem which decreased the cost of fuel purchases and outage-related costs compared to 1997, from decreased operating and maintenance expense and from reduced uncollectible expenses.

The increase in 1998 third quarter results was due primarily to increased operating revenues net of related fuel costs. Revenues from wholesale sales increased significantly compared to 1997. Third quarter earnings also benefited from the full return to service of Salem, reduction of operating and maintenance costs, reduction of uncollectible expenses and a one-time refund of gross receipts tax.

The increase in the fourth quarter results was primarily due to the extraordinary charge of $8.24 per share recorded in 1997 resulting from deregulation of the Company's electric generation operations; several one-time adjustments for changes in employee benefits; write-offs of information systems development charges reflecting clarification of accounting guidelines and additional reserves to revise estimates for accruals; higher income tax adjustments; and higher losses from the Company's non-utility ventures. This increase was partially offset by an Early Retirement and Severance charge and an extraordinary charge for the premiums paid in connection with the redemption of higher-cost, long-term debt recorded in the fourth quarter of 1998.

Financial Statistics

Summary of Earnings and Financial Condition

For the Years Ended December 31,	**1998**	1997	1996	1995	1994	1993
					Millions of Dollars, except per share data	
Income Data						
Operating Revenues	**$ 5,210**	$ 4,618	$ 4,284	$ 4,186	$ 4,041	$ 3,988
Operating Income	**1,283**	1,006	1,249	1,401	1,064	1,390
Income before Extraordinary Item	**532**	337	517	610	427	591
Extraordinary Item (net of income taxes)	**(20)**	(1,834)	—	—	—	—
Net Income (Loss)	**513**	(1,497)	517	610	427	591
Earnings Applicable to Common Stock	**500**	(1,514)	499	587	389	542
Earnings per Average Common Share Before Extraordinary Item	**2.33**	1.44	2.24	2.64	1.76	2.45
Extraordinary Item	**(0.09)**	(8.24)	—	—	—	—
Earnings per Average Common Share	**2.24**	(6.80)	2.24	2.64	1.76	2.45
Dividends per Common Share	**1.00**	1.80	1.755	1.65	1.545	1.43
Common Stock Equity	**13.61**	12.25	20.88	20.40	19.41	19.25
Average Shares of Common Stock Outstanding (Millions)	**223.2**	222.5	222.5	221.9	221.6	221.1
At December 31,						
Balance Sheet Data						
Net Utility Plant	**$ 4,610**	$ 4,495	$ 10,760	$ 10,758	$ 10,829	$ 10,763
Leased Property, net	**154**	176	182	181	174	194
Total Current Assets	**569**	1,003	420	426	427	515
Total Deferred Debits and Other Assets	**6,715**	6,683	3,899	3,944	3,992	3,905
Total Assets	**$ 12,048**	$ 12,357	$ 15,261	$ 15,309	$ 15,422	$ 15,377
Common Shareholders' Equity	**$ 3,057**	$ 2,727	$ 4,646	$ 4,531	$ 4,303	$ 4,263
Preferred and Preference Stock Without Mandatory Redemption	**137**	137	199	199	277	423
Preferred and Preference Stock With Mandatory Redemption	**93**	93	93	93	93	187
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership	**349**	352	302	302	221	—
Long-Term Debt	**2,920**	3,853	3,936	4,199	4,786	4,884
Total Capitalization	**6,556**	7,162	9,176	9,324	9,680	9,757
Total Current Liabilities	**1,735**	1,619	1,103	1,052	850	954
Total Deferred Credits and Other Liabilities	**3,757**	3,576	4,982	4,933	4,892	4,666
Total Capitalization and Liabilities	**$ 12,048**	$ 12,357	$ 15,261	$ 15,309	$ 15,422	$ 15,377

Operating Statistics

For the Years Ended December 31,	**1998**	1997	1996	1995	1994	1993
Electric Operations						
Output ***(Millions of Kilowatthours)***						
Fossil	**10,262**	9,659	10,856	10,792	11,239	10,352
Nuclear	**29,732**	25,853	24,373	25,499	28,195	27,026
Hydro	**1,715**	1,558	2,404	1,425	1,970	1,699
Pumped storage output	**1,426**	1,403	1,540	1,741	1,596	1,478
Pumped storage input	**(1,853)**	(1,924)	(2,230)	(2,507)	(2,256)	(2,192)
Purchase and interchange	**34,075**	29,615	19,539	13,945	6,164	6,447
Internal combustion	**176**	144	179	175	106	56
Total electric output	**75,533**	66,308	56,661	51,070	47,014	44,866
Sales ***(Millions of Kilowatthours)***						
Residential	**10,623**	10,407	10,671	10,636	10,859	10,609
Small commercial and industrial	**6,888**	6,685	6,491	6,200	6,150	5,769
Large commercial and industrial	**15,678**	15,034	15,208	15,763	15,968	15,956
Other	**803**	841	902	860	791	771
Unbilled	**131**	70	(327)	535	(205)	31
Service territory	**34,123**	33,037	32,945	33,994	33,563	33,136
Interchange sales	**3,483**	1,927	935	496	768	457
Sales to other utilities	**37,258**	28,893	20,243	14,041	10,039	8,670
Total electric sales	**74,864**	63,857	54,123	48,531	44,370	42,263
Number of Customers, ***December 31,***						
Residential	**1,343,791**	1,333,861	1,324,448	1,321,379	1,350,210	1,341,873
Small commercial and industrial	**145,055**	144,142	142,431	141,653	143,605	142,363
Large commercial and industrial	**3,248**	3,308	3,299	3,394	3,603	3,742
Other	**1,150**	1,094	1,051	959	944	888
Total electric customers	**1,493,244**	1,482,405	1,471,229	1,467,385	1,498,362	1,488,86
Operating Revenues ***(Millions of Dollars)***						
Residential	**$ 1,377**	$ 1,357	$ 1,370	$ 1,379	$ 1,371	$ 1,351
Small commercial and industrial	**784**	779	749	730	710	679
Large commercial and industrial	**1,067**	1,077	1,098	1,135	1,149	1,168
Other	**150**	148	140	137	136	161
Unbilled	**1**	19	(26)	43	(11)	(1)
Service territory	**3,379**	3,380	3,331	3,424	3,355	3,358
Interchange sales	**211**	59	26	17	23	14
Sales to other utilities	**1,221**	728	498	334	247	233
Total electric revenues	**$ 4,811**	$ 4,167	$ 3,855	$ 3,775	$ 3,625	$ 3,605
Operating Expenses						
Operating expenses, excluding depreciation and amortization	**$ 2,993**	$ 2,698	$ 2,244	$ 2,026	$ 2,209	$ 1,894
Depreciation and amortization	**611**	553	462	431	416	401
Total operating expenses	**3,604**	3,251	2,706	2,457	2,625	2,295
Electric Operating Income	**$ 1,207**	$ 916	$ 1,149	$ 1,318	$ 1,000	$ 1,310
Average Use per Residential Customer ***(Kilowatthours)***						
Without electric heating	**6,948**	6,695	6,771	6,908	6,736	6,727
With electric heating	**15,398**	16,400	17,946	17,189	17,527	17,096
All customers	**7,935**	7,830	8,074	8,130	8,041	7,970
Electric Peak Load, Demand *(Thousands of Kilowatts)*	**7,108**	7,390	6,509	7,244	7,227	7,100
Net Electric Generating Capacity-Year-end Summer Rating *(Thousands of Kilowatts)*	**9,262**	9,204	9,201	9,078	8,956	8,877
Cost of Fuel per Million BTU	**$ 0.82**	$ 0.84	$ 0.93	$ 0.87	$ 0.89	$ 0.90
BTU per Net Kilowatthour Generated	**10,496**	10,737	10,682	10,705	11,617	10,675

Operating Statistics *(continued)*

For the Years Ended December 31,	**1998**	1997	1996	1995	1994	1993
Gas Operations						
Sales *(Millions of Cubic Feet)*						
Residential	**1,496**	1,614	1,681	1,516	1,636	1,637
House heating	**28,402**	32,666	35,471	30,698	32,246	30,242
Commercial and industrial	**16,757**	19,830	20,999	18,464	19,762	18,635
Other	**554**	673	2,571	1,582	7,039	9,733
Unbilled	**(440)**	212	(1,306)	1,710	(474)	676
Total gas sales	**46,769**	54,995	59,416	53,970	60,209	60,923
Gas transported for customers	**28,204**	30,412	27,891	48,531	29,801	22,946
Total gas sales and gas transported	**74,973**	85,407	87,307	102,501	90,010	83,869
Number of Customers						
Residential	**55,417**	55,592	56,003	56,533	57,122	59,573
House heating	**324,081**	314,335	303,996	295,481	287,481	277,500
Commercial and industrial	**35,931**	35,215	34,182	33,308	32,292	31,573
Total gas customers	**415,429**	405,142	394,181	385,322	376,895	368,646
Operating Revenues *(Millions of Dollars)*						
Residential	**$ 16**	$ 17	$ 16	$ 15	$ 16	$ 15
House heating	**236**	265	249	236	238	202
Commercial and industrial	**125**	145	133	126	128	110
Other	**2**	3	11	5	20	28
Unbilled	**(3)**	(1)	(4)	7	(3)	5
Subtotal	**376**	429	405	389	399	360
Other revenues (including gas transported for customers)	**24**	22	24	22	17	23
Total gas revenues	**$ 400**	$ 451	$ 429	$ 411	$ 416	$ 383
Operating Expenses						
Operating expenses, excluding depreciation and amortization	**$ 291**	$ 333	$ 302	$ 302	$ 326	$ 279
Depreciation and amortization	**32**	28	27	26	26	24
Total operating expenses	**323**	361	329	328	352	303
Gas Operating Income	**$ 77**	$ 90	$ 100	$ 83	$ 64	$ 80

Securities Statistics

Ratings on PECO Energy Company's securities

	Mortgage Bonds		Preferred Stock	
Agency	Rating	Date Established	Rating	Date Established
Duff and Phelps, Inc.	A-	10/98	BBB	10/98
Fitch Investors Service, Inc.	A-	9/92	BBB+	9/92
Moody's Investors Service	Baa1	4/92	baa2	4/92
Standard & Poor's Corporation	BBB+	4/92	BBB-	2/99

NYSE-Composite Common Stock Prices, Earnings and Dividends by Quarter *(Per Share)*

	1998				1997			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	**$42-3/16**	**$ 36-3/4**	**$ 30-5/8**	**$24-11/16**	$ 25-1/8	$24-5/16	$ 21-1/8	$ 26-3/8
Low price	**$ 36-1/2**	**$ 28-1/2**	**$21-3/16**	**$ 18-7/8**	$21-7/16	$ 20-3/4	$ 18-3/4	$ 20
Close	**$ 41-3/4**	**$ 36-3/4**	**$29-3/16**	**$ 22-1/8**	$ 24-1/4	$23-7/16	$ 21	$ 20-3/8
Earnings	**$ (0.13)**	**$ 1.21**	**$ 0.66**	**$ 0.50**	$ (8.51)	$ 0.69	$ 0.53	$ 0.49
Dividends	**$ 0.25**	**$ 0.25**	**$ 0.25**	**$ 0.25**	$ 0.45	$ 0.45	$ 0.45	$ 0.45

Board of Directors

Susan W. Catherwood (55)
Chairman, Trustee Board,
The University of Pennsylvania
Medical Center and Health System

Daniel L. Cooper (63)
Former Vice President and General
Manager, Nuclear Services Division
Gilbert/Commonwealth, Inc.

M. Walter D'Alessio (65)
President and Chief Executive
Officer,
Legg Mason Real Estate Services
(Commercial mortgage banking
and pension fund advisors)

G. Fred DiBona, Jr. (47)(1)
President and Chief Executive
Officer,
Independence Blue Cross

R. Keith Elliott (56)
Chairman, Chief Executive Officer,
Hercules, Inc.

Richard H. Glanton (52)(1)
Partner of the law firm Reed Smith
Shaw and McClay

Rosemarie B. Greco (52)(2)
Former President and
Chief Executive Officer,
Private Industry Council

Corbin A. McNeill, Jr. (59)(1)
Chairman of the Board
President and Chief Executive
Officer of the Company

John M. Palms, PhD. (63)
President,
University of South Carolina

Joseph F. Paquette, Jr. (64)(1)
Former Chairman of the Board of
Directors of the Company

Ronald Rubin (67)
Chief Executive Officer,
Pennsylvania Real Estate Investment
Trust

Robert Subin (60)
Former Senior Vice President,
Campbell Soup Company

Officers

Corbin A. McNeill, Jr. (59)
Chairman of the Board of Directors
President and Chief Executive
Officer

Gerald R. Rainey (49)(9)
President and Chief Nuclear Officer,
PECO Nuclear

Nancy J. Bessey (45)(6)
President, Power Team

Gregory A. Cucchi (49)(10)
Senior Vice President,
Corporate and President,
PECO Energy Ventures

James W. Durham (61)
Senior Vice President
and General Counsel

Michael J. Egan (45)
Senior Vice President, Finance
and Chief Financial Officer

Kenneth G. Lawrence (51)(10)
Senior Vice President,
Corporate and President,
PECO Energy Distribution

William H. Smith, III (50)
Senior Vice President,
Business Services Group

David W. Woods (41)(14)
Senior Vice President,
Corporate and Public Affairs

John B. Cotton (53)(11)
Special Projects, PECO Nuclear

John Doering, Jr. (55)(4)
Vice President, Peach Bottom
Atomic Power Station

Gregory P. Dudkin (41)(6)
Vice President, Operations,
PECO Energy Distribution

Drew B. Fetters (47)(10)
Vice President,
Nuclear Development,
PECO Nuclear

Jean H. Gibson (42)(8)
Vice President and Controller

Joseph J. Hagan (48)(16)
Senior Vice President,
Nuclear Operations,
PECO Nuclear

Paul E. Haviland (44)(5)
Vice President,
Corporate Development

Thomas P. Hill, Jr. (50)(7)
Vice President, Regulatory and
External Affairs, PECO Energy
Distribution

Christine A. Jacobs (46)(13)
Vice President, Support Services

Suzanne L. Keenan (34)(6)
Vice President, Customer &
Marketing Services,
PECO Energy Distribution

Cassandra A. Matthews (48)
Vice President, Information
Technology and Chief Information
Officer

John P. McElwain (48)(15)
Vice President,
Nuclear Projects, PECO Nuclear

J. Barry Mitchell (51)
Vice President, Treasury and
Evaluation, and Treasurer

James A. Muntz (41)(16)
Vice President, Fossil Operations

James D. von Suskil (52)(3)
Vice President,
Limerick Generating Station,
PECO Nuclear

Richard G. White (40)(12)
Vice President, Corporate Planning

Katherine K. Combs (48)
Corporate Secretary

Edward J. Cullen, Jr. (51)
Assistant Corporate Secretary

Todd D. Cutler (38)
Assistant Corporate Secretary

Diana Moy Kelly (44)
Assistant Treasurer

George R. Shicora (52)
Assistant Treasurer and
Cash Manager

(1) Member of the Executive Committee of the Board of Directors
(2) Elected February 23, 1998
(3) Effective January 26, 1998
(4) Effective March 2, 1998
(5) Effective March 4, 1998
(6) Effective April 8, 1998
(7) Effective April 9, 1998
(8) Effective May 31, 1998
(9) Effective June 1, 1998
(10) Effective June 22, 1998
(11) Effective August 14, 1998
(12) Effective September 28, 1998
(13) Effective November 9, 1998
(14) Effective December 1, 1998
(15) Effective January 6, 1999, no longer an officer of PECO Energy
(16) Effective January 26, 1999

Shareholder Information

Stock Exchange Listings

Most Company securities are listed on the New York Stock Exchange and the Philadelphia Stock Exchange under PE.

Dividends

The Company has paid dividends on its common stock continually since 1902. The Board of Directors normally considers common stock dividends for payment in March, June, September and December. The Company expects that the $1.00 per share dividend paid to common shareholders in 1998 is fully taxable as dividend income for federal income tax purposes.

Shareholders may use their dividends to purchase additional shares of common stock through the Company's Dividend Reinvestment and Stock Purchase Plan (Plan). The Company pays all brokerage and service fees for Plan purchases. All shareholders have the opportunity to invest additional funds in common stock of the Company, whether or not they have their dividends reinvested, with all purchasing fees paid by the Company.

In 1998, over 57 percent of the Company's common shareholders were participants in the Plan. Information concerning the Plan may be obtained from: EquiServe, PECO Energy Company Plan, P.O. Box 2598, Jersey City, NJ 07303-2598.

Comments Welcomed

The Company is always pleased to answer questions and provide information. Please address your comments to Katherine K. Combs, Corporate Secretary, PECO Energy Company, 2301 Market Street, P.O. Box 8699, Philadelphia, PA 19101-8699.

Inquiries relating to shareholder accounting records, stock transfer and change of address should be directed to: EquiServe, P.O. Box 2500, Jersey City, NJ 07303-2500.

Toll-Free Telephone Lines

Toll-free telephone lines are available to the Company's shareholders for inquiries concerning their stock ownership. Calls should be directed to 1-800-626-8729.

For current Company news call 1-888-340-7326

Annual Meeting

The Annual Meeting of the Shareholders of the Company will be held at the Sunnybrook Ballroom and Conference Center in Pottstown, Pennsylvania on April 27, 1999, at 9:30 AM. The record date for voting at the shareholders' meeting is March 5, 1999. Prompt return of proxies will be appreciated.

To vote your proxy over the internet visit
http://www.vote-by-net.com

To receive future Annual Reports and proxy statements electronically, sign-up at:
http://www.vote-by-net.com/signup/peco

Form 10-K

Form 10-K, the annual report filed with the Securities and Exchange Commission, is available without charge to shareholders by calling 1-888-340-7326 or by obtaining a copy from our internet site http://www/peco.com/investor.

Shareholders

The Company had 142,794 shareholders of record of common stock as of December 31, 1998.

Transfer Agents and Registrars

Preferred and Common Stock Registrar and Transfer Agent:
First Chicago Trust, Division of EquiServe, (1-800-626-8729)
P.O. Box 2500, Jersey City, NJ 07303-2500

First and Refunding Mortgage Bond Trustee:
First Union National Bank, (1-800-665-9343)
Corporate Trust Operations Customer Information Center
Redemption Bldg 3C3
1525 West W.T. Harris Blvd.Charlotte, NC 28288-1153

Internet Site

Visit our internet site at http://www.peco.com

General Office

2301 Market Street
Philadelphia, Pennsylvania 19103
(215) 841-4000

PECO ENERGY®

PECO Energy Company
2301 Market Street
P.O.Box 8699
Philadelphia, PA 19101-8699

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 1998

OR

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

Commission file number 1-1405

DELMARVA POWER & LIGHT COMPANY

(Exact name of registrant as specified in its charter)

Delaware & Virginia	**51-0084283**
(States or other jurisdictions of incorporation or organization)	**(I.R.S. Employer Identification No.)**

800 King Street, P. O. Box 231
Wilmington, Delaware 19899
(Address of principal executive offices)

Registrant's telephone number (302) 429-3114

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

Title of each class	Name of each exchange on which registered
First Mortgage Bonds (Series issued prior to 1968)	New York Stock Exchange and Philadelphia Stock Exchange
Preferred Stock, Cumulative, Par Value $100.00 (Series issued prior to 1978)	Philadelphia Stock Exchange
8.125% Cumulative Trust Preferred Capital Securities of Delmarva Financing I (Liquidation Value of $25.00)	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 or any amendment to this Form 10-K ☑

All 1,000 issued and outstanding shares of Delmarva Power & Light Company common stock, $2.25 per share par value, are owned by Conectiv.

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GLOSSARY

The following glossary lists the abbreviations used in this report.

Term	Definition
1992 Energy Act	National Energy Policy Act of 1992
ACE	Atlantic City Electric Company
AFUDC	Allowance For Funds Used During Construction
Atlantic	Atlantic Energy, Inc.
APB	Accounting Principles Board
Bcf	Billion Cubic Feet
CAM	Cost Accounting Manual
CRP	Conectiv Resource Partners, Inc.
Clean Water Act	Federal Water Pollution Control Act
Debentures	8.125% Junior Subordinated Debentures
D&D Fund	Decontamination & Decommissioning Fund
DNREC	Delaware Department of Natural Resources and Environmental Control
DOE	United States Department of Energy
DPL	Delmarva Power & Light Company
DPSC	Delaware Public Service Commission
DRIP	Dividend Reinvestment and Common Share Purchase Plan
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
HVAC	Heating, ventilation, and air conditioning
kWh	Kilowatt-hour
Litigation Reform Act	The Private Securities Litigation Reform Act of 1995
LLRW	Low Level Radioactive Waste
LMP	Locational Marginal Pricing
LTIP	Long-Term Incentive Plan
Mcf	Thousand Cubic Feet
Merger	A series of merger transactions by which DPL and ACE became subsidiaries of Conectiv
Mortgage	Mortgage and Deed of Trust
MPSC	Maryland Public Service Commission
MW	Megawatt
MWH	Megawatt-hour
NERC	North American Electric Reliability Council
NJPDES	New Jersey Pollution Discharge Elimination System
NOTR	Northeast Ozone Transport Region
NOx	Oxides of Nitrogen
NPDES	National Pollution Discharge Elimination System
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
ODEC	Old Dominion Electric Cooperative
Peach Bottom	Peach Bottom Atomic Power Station
PECO	PECO Energy Company
PJM Interconnection	Pennsylvania-New Jersey-Maryland Interconnection Association
PPPP	Power Plant Performance Program

Term	Definition
PSE&G	Public Service Electric and Gas Company
PUHCA	Public Utility Holding Company Act of 1935
RACT	Reasonably Available Control Technology
RTP	Real Time Pricing
Salem	Salem Nuclear Generating Station
SALP	Systematic Assessment of Licensee Performance
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS No. 71	SFAS No. 71, ''Accounting For the Effects of Certain Types of Regulation''
SFAS No. 88	SFAS No. 88, ''Employers' Accounting For Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits''
SFAS No. 128	SFAS No. 128, ''Earnings Per Share''
SFAS No. 131	SFAS No. 131, ''Disclosures about Segments of an Enterprise and Related Information''
SFAS No. 133	SFAS No. 133, ''Accounting for Derivative Instruments and Hedging Activities''
SO_2	Sulfur Dioxide
USEPA	United States Environmental Protection Agency
Vienna	Vienna Generating Station
VRDB	Variable Rate Demand Bonds
VSCC	Virginia State Corporation Commission
Westinghouse	Westinghouse Electric Corporation

PART I

Item 1. Business

General

Delmarva Power & Light Company (DPL) is a regulated public electric and gas utility and a subsidiary of Conectiv, which is a Delaware corporation and a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). DPL was incorporated in Delaware in 1909 and in Virginia in 1979 and holds the franchises necessary to provide regulated electric and gas service in its service territory.

DPL's electric utility business activities are primarily generating, purchasing, delivering, and selling electricity. DPL serves approximately 455,300 electric customers within its service territory, which has a population of approximately 1.2 million and covers an area of about 6,000 square miles on the Delmarva Peninsula, which includes Delaware, ten primarily Eastern Shore counties in Maryland, and the Eastern Shore of Virginia. DPL also sells electricity outside its service territory (off-system) and in markets that are not subject to price regulation.

DPL provides regulated gas service (supply and/or transportation) to approximately 105,700 customers located in a service territory, which has a population of approximately 485,000 and covers an area of about 275 square miles in northern Delaware, including the City of Wilmington. DPL also sells gas off-system and in markets which are not subject to price regulation.

In 1998, DPL's sources of revenues were as follows: regulated electricity sales—55.5%; non-regulated electricity sales—14.5%; regulated gas sales—5.6%; non-regulated gas sales—22.5%; and other services—1.9%.

DPL's utility business is subject to regulation with respect to its retail electric sales by the Delaware Public Service Commission (DPSC), Maryland Public Service Commission (MPSC), and the Virginia State Corporation Commission (VSCC). The Federal Energy Regulatory Commission (FERC) also has regulatory authority over certain aspects of DPL's electric utility business, including the transmission of electricity, the sale of electricity to municipalities and electric cooperatives, and interchange and other purchases and sales of electricity involving other utilities. DPL is also subject to regulation by the Pennsylvania Public Utility Commission in limited respects concerning property and operations in Pennsylvania.

On March 1, 1998, DPL and Atlantic City Electric Company (ACE) became wholly-owned subsidiaries of Conectiv. Before the Merger, Atlantic Energy, Inc. (Atlantic) owned ACE, an electric utility serving the southern one-third of New Jersey, and nonutility subsidiaries. As a result of the Merger, Atlantic no longer exists and Conectiv owns, directly or indirectly, DPL, ACE, and nonutility subsidiaries formerly held separately by DPL and Atlantic. DPL's former nonutility subsidiaries included Conectiv Services, Inc. (heating, ventilation, and air conditioning construction and services), Conectiv Communications, Inc. (local and long-distance phone service), and Delmarva Capital Investments, Inc. (various nonutility businesses). Conectiv is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA), which imposes certain restrictions on the operations of registered holding companies and their subsidiaries.

At December 31, 1998, DPL had 1,259 employees, of which 988 were represented by collective bargaining labor organizations. During 1998, DPL reduced its workforce by 1,461 employees, including 421 employees separated through Merger-related employee separation programs and 1,040 employees transferred to Conectiv Resource Partners, Inc. (CRP), a Conectiv subsidiary and service company established pursuant to PUHCA regulations. CRP provides a variety of support services to Conectiv subsidiaries, and its employees are primarily former DPL and ACE employees. The costs of CRP are directly assigned, distributed and allocated to the Conectiv subsidiaries using CRP's services, including DPL.

For additional information about the Merger, refer to Note 4 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II.

For information concerning DPL's business segments, see Note 21 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II.

Competition and Electric Utility Industry Restructuring

For information concerning restructuring the electric utility industry in Delaware, Maryland, and Virginia, see Note 6 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II. Generally, with restructuring, the supply component of the price charged to a customer for electricity will be deregulated, and electricity suppliers will compete to supply electricity to customers. Customers will continue to pay the local utility a regulated price for delivery of electricity over the transmission and distribution system. As electric utility industry restructuring is implemented in DPL's and other utilities' service territories, gross margins earned from supplying electricity are expected to decrease as competition to supply customers with electricity increases. Delaware legislation is expected to be enacted which would begin phasing-in choice of electricity suppliers to customers beginning October 1, 1999. In Maryland, competition to supply electric customers is expected to be phased in beginning July 3, 2000, over a 3-year period. In Virginia, retail electric competition is expected to be phased-in beginning January 1, 2002.

As a greater percentage of DPL's revenues become subject to competition, financial risks and rewards, and the volatility of earnings are expected to increase. DPL's ability to continue reducing costs by streamlining operations, regulatory decisions pursuant to restructurings, retention of existing customers and the ability to gain new customers are significant determinants of DPL's future success.

Electric Business

Installed Capacity

The megawatts (MW) of net installed summer electric generating capacity available to DPL to serve its peak load as of December 31, 1998, are presented below. See Item 2, Properties, for additional information.

Source of Capacity	MW	% of Total
Coal-fired generating units	1,153	33
Oil-fired generating units	598	17
Combustion turbines/combined cycle generating units	674	19
Nuclear generating units	328	9
Diesel units	23	—
Long-term purchased capacity	237	7
Customer-owned capacity	57	2
Subtotal	3,070	87
Short-term purchased capacity	449	13
Total	3,519	100

The net generating capacity available for operations at any time may be less than the total net installed generating capacity due to generating units being out of service for inspection, maintenance, repairs, or unforeseen circumstances.

As restructuring of the electric utility industry is implemented, DPL expects to sell some of its generating units. DPL has identified certain generating assets that may be sold, but has not determined when such sale, or sales, would occur.

DPL also has demand-side management programs which provide DPL with the ability to reduce its peak load by approximately 272 MW.

Electricity Supply

As a member of the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM Interconnection), DPL is obligated to maintain capacity levels based on its allocated share of estimated aggregate PJM Interconnection capacity requirements. (The PJM Interconnection is discussed below.) DPL periodically updates its forecast of peak demand and PJM Interconnection reserve requirements, and re-evaluates resources available to supply projected growth. Any short-term capacity deficiencies related to obligations to the PJM Interconnection are expected to be satisfied through short-term capacity-only purchases. Incremental energy supply needs are expected to be filled through purchased power.

DPL's peak load in 1998 was 3,085 MW on July 23, an 8.0% increase from DPL's previous historical peak demand of 2,857 MW which occurred on July 15, 1997. DPL's capacity obligation to the PJM Interconnection, including a reserve margin, is based on normal weather conditions and full implementation of its demand-side management programs. Under these conditions, DPL's 1998 peak demand would have been approximately 2,952 MW. DPL's installed capacity of 3,481 MW at the time of the peak resulted in a reserve margin of 18%, computed under PJM Interconnection guidelines. DPL's reserve obligation to the PJM Interconnection is approximately 18%.

The sources of electricity supplied to DPL's customers in its service territory during 1998, 1997, and 1996 are shown below.

Source of Electricity	1998	1997	1996
Generation fuel type			
Coal	34%	35%	38%
Oil/Natural Gas	18	20	29
Nuclear	16	10	9
Interchange and Purchased Power	32	35	24
Total	100%	100%	100%

Pennsylvania-New Jersey-Maryland Interconnection Association

As a member of the PJM Interconnection, DPL's generation and transmission facilities are operated on an integrated basis with other electricity suppliers in Pennsylvania, New Jersey, Maryland, and the District of Columbia, and are interconnected with other major utilities in the United States. This power pool improves the reliability and operating economies of the systems in the group and provides capital economies by permitting shared reserve requirements. The PJM Interconnection's installed capacity as of December 31, 1998, was 57,551 MW. The PJM Interconnection's peak demand during 1998 was 48,663 MW on August 15, which resulted in a summer reserve margin of 18.2% (based on installed capacity of 57,511 MW on that date).

On October 15, 1998, the PJM Interconnection began operating a centralized capacity credit market, providing a new option to participants for procuring and selling surplus capacity to meet reliability obligations within the PJM Interconnection region. Capacity is the capability to produce electric power, typically from owned generation or third-party purchase contracts and differs from the electric energy markets, which trade the actual energy being generated. This market facilitates the selling and buying of capacity for participants by providing a single point of contact for market participants and a published capacity market clearing price.

Effective April 1, 1998, the PJM Interconnection implemented locational marginal pricing (LMP) to establish the market clearing prices for electric energy and to price electric transmission usage based upon costs associated with transmission system congestion. When there is no congestion on the power system and energy is flowing on the grid in an unconstrained manner, energy prices are cleared at the highest bid accepted by the PJM Interconnection for the entire PJM Interconnection region. When a limit is reached on the transmission grid, the PJM Interconnection will operate generators to preserve system reliability. LMP allows the PJM Interconnection to send price signals to raise and lower generator output when the power flows are constrained. Different energy

market clearing prices are paid by wholesale power buyers and sellers on the power grid that reflect the value relative to a system constraint. LMP provides for an efficient allocation of congestion costs to transmission users within the PJM Interconnection region. The FERC has approved the use of the LMP congestion management system to allow electric energy market participants with power contracts on neighboring electric systems to compensate the PJM Interconnection for any unintended flows on the PJM Interconnection system, rather than forcing those participants to curtail their contracts.

Currently, the PJM Interconnection Operating Agreement requires bids to sell electricity received from generation located within the PJM Interconnection control area not to exceed the variable cost of producing such electricity. Transactions that are bid into the PJM pool from generation located outside the PJM Interconnection control area are capped at $1,000 per megawatt hour. All power providers are paid the LMP set through power providers' bids. Certain PJM Interconnection members have requested that FERC revise the PJM Interconnection Operating Agreement to allow the submission of market based bids to the PJM Interconnection energy market.

Purchased Power

In conjunction with its acquisition of Conowingo Power Company in 1995, DPL purchases from PECO Energy Company (PECO) 237 MW of base-load capacity and associated energy, which increases to 279 MW by 2006 when the contract expires. DPL is also currently purchasing 105 MW of capacity under one-year contracts and 344 MW of capacity through agreements with terms of less than one year.

Nuclear Power Plants

DPL's nuclear capacity is provided by Peach Bottom Atomic Power Station (Peach Bottom) Units 2 and 3 and by Salem Nuclear Generating Station (Salem) Units 1 and 2. DPL jointly owns these units, as tenants in common, with PECO, ACE and Public Service Electric and Gas Company (PSE&G). The Peach Bottom units are operated by PECO and have a combined summer capacity of 2,186 MW, of which DPL is entitled to 164 MW (7.51%). The Salem units are operated by PSE&G and have a combined summer capacity of 2,212 MW, of which DPL is entitled to 164 MW (7.41%).

DPL's ownership share in nuclear power plants provided approximately 9% of its installed capacity as of December 31, 1998. In 1998, DPL's share of output from the jointly-owned nuclear power plants provided 16% of the electricity used by DPL's customers. See Note 9 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II for information about DPL's investment in jointly-owned generating stations.

The operation of nuclear generating units is regulated by the Nuclear Regulatory Commission (NRC). Such regulation requires that all aspects of plant operation be conducted in accordance with NRC safety and environmental requirements and that continuous demonstrations be made to the NRC that plant operations meet applicable requirements. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate.

As a by-product of nuclear operations, nuclear generating units produce low-level radioactive waste (LLRW). LLRW is accumulated on-site until shipped to a federally licensed permanent disposal facility. Salem and Peach Bottom have on-site interim storage facilities with five-year storage capacities.

For a discussion of the cycle of production, use and disposal of nuclear fuel, see ''Nuclear'' on page I-6.

For a discussion of DPL's funding of its share of the estimated future cost of decommissioning the Salem and Peach Bottom nuclear reactors, see Note 8 to DPL's 1998 Consolidated Financial Statements included in Part II, Item 8.

The NRC is requiring nuclear plant operators to report by July 1, 1999, that their nuclear power plants are Year 2000 ready, or will be Year 2000 ready, by January 1, 2000. PSE&G and PECO have informed DPL that they are on schedule to meet the July 1, 1999 response date and that their nuclear operations' Year 2000 programs will make Salem and Peach Bottom Year 2000 ready by January 1, 2000.

Salem Units 1 and 2 were removed from operation by PSE&G in the second quarter of 1995 due to operational problems, and maintenance and safety concerns. Due to degradation of a significant number of tubes in the Unit 1 steam generators, PSE&G replaced the Unit 1 steam generators. After receiving NRC authorization, PSE&G returned Unit 2 to service on August 30, 1997, and Unit 1 to service on April 17, 1998. On July 29, 1998, the NRC removed Salem from its "watch list" of troubled nuclear plants. The Salem Unit 2 steam generators will be inspected for tube degradation in upcoming outages.

See Note 18 to DPL's 1998 Consolidated Financial Statements included in Part II, Item 8, for information concerning DPL's lawsuit against Westinghouse Electric Corporation, the designer and manufacturer of the Salem steam generators, and the financial impact of the outages.

Systematic Assessment of Licensee Performance (SALP) reports issued by the NRC rate licensee performance in four assessment areas: Operations, Maintenance, Engineering and Plant Support. Ratings range from a high of "1" to a low of "3." In September 1998, the NRC issued a SALP on the performance of activities at Salem for the period March 1, 1997, to August 1, 1998. Salem received a rating of 1 in Operations, a 2 in Maintenance, a 2 in Engineering, and a 1 in Plant Support. The NRC noted that the overall performance at Salem improved, as demonstrated by a nearly event-free return of both units to operation following the extended outage.

On July 17, 1997, the NRC issued a SALP report on Peach Bottom for the period October 15, 1995, to June 7, 1997. Peach Bottom received a rating of 1 in the areas of Operations, Maintenance, and Plant Support, and 2 in Engineering.

On September 16, 1998, the NRC announced that it was suspending the SALP report process until it completes a review of its nuclear power plant performance assessment process. The SALP process has not yet been resumed or replaced.

Fuel Supply for Electric Generation

DPL's electric generating capacity by fuel type is shown under "Installed Capacity" on page I-2. To facilitate the purchase of adequate amounts of fuel at reasonable prices, DPL contracts with various suppliers of coal, oil, and natural gas on both a long- and short-term basis. DPL's long-term coal contracts generally contain provisions for periodic and limited price adjustments, which are based on current market prices. Oil and natural gas contracts generally are of shorter term with prices determined by market-based indices.

Coal

Edge Moor Units 3 and 4, and the Indian River, Keystone and Conemaugh Generating Stations are coal-fired. During 1998, 47% of DPL's coal supply was purchased under contracts less than three years in duration, 48% under long-term contracts (up to ten years), and the balance on the spot market. Approximately 69% of DPL's projected coal requirements are expected to be provided under supply contracts. DPL does not anticipate any difficulty in obtaining adequate amounts of coal at reasonable prices.

Oil

Currently, 100% of the residual oil used in Edge Moor Unit 5 is purchased on a spot basis. Natural gas is used when economically feasible. A two-year residual oil supply contract that expires in 1999 provides 90% to 100% of the fuel supply requirements for the Vienna Generating Station (Vienna). Any amount over 90% of Vienna's requirements may be purchased in the spot market.

Gas

Natural gas is the primary fuel for the three combustion turbines at DPL's Hay Road combustion turbines and a secondary fuel at Edge Moor Units 3, 4, and 5. Natural gas for these generating units is purchased on a

firm or interruptible basis from suppliers such as marketers, producers, and utilities. The gas is delivered to DPL by interstate pipelines under a mix of firm and interruptible transportation agreements. The secondary fuel for the Hay Road combustion turbines is low-sulfur diesel fuel, which is purchased in the spot market.

Nuclear

The supply of fuel for nuclear generating units involves the mining and milling of uranium ore to uranium concentrate, conversion of the uranium concentrate to uranium hexaflouride, enrichment of the uranium hexaflouride gas, conversion of the enriched gas to fuel pellets, and fabrication of fuel assemblies. After spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The federal government has an obligation for the transportation and ultimate disposal of the spent fuel, as discussed below.

PSE&G has informed DPL it has several long-term contracts with uranium ore operators, converters, enrichers and fabricators to process uranium ore to uranium concentrate to meet the currently projected requirements for Salem. DPL has also been advised by PECO that it has similar contracts to satisfy the fuel requirements of Peach Bottom. Currently, there is an adequate supply of nuclear fuel for Salem and Peach Bottom.

In conformity with the Nuclear Waste Policy Act of 1982 (NWPA), PSE&G and PECO have entered into contracts with the United States Department of Energy (DOE) on behalf of the joint owners providing that the federal government shall for a fee take title to, transport, and dispose of spent nuclear fuel and high level radioactive waste from the Salem and Peach Bottom reactors. In accordance with the NWPA, DPL pays the DOE one-tenth of one cent per kWh of nuclear generation (net of station use) for the future cost of spent nuclear fuel disposal. Under the NWPA, the DOE was to begin accepting spent fuel for permanent off-site storage no later than January 1998. However, no such repositories are in service or under construction. The DOE has stated that it would not be able to open a permanent, high level nuclear waste storage facility until 2010, at the earliest.

Pursuant to NRC rules, spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in independent spent nuclear fuel storage installations located at or away from reactor sites for at least 30 years beyond the licensed life for operation (which may include the term of a revised or renewed license).

PSE&G has advised DPL that, as a result of reracking the two spent fuel storage pools at Salem, the availability of spent fuel storage capacity is estimated to be adequate through 2012 for Unit 1 and 2016 for Unit 2. PECO has advised DPL that spent fuel racks at Peach Bottom have adequate storage capacity until 2000 for Unit 2 and until 2001 for Unit 3. PECO has also advised DPL that it is constructing an on-site dry storage facility, which is expected to be operational in 2000, to provide additional storage capacity.

Electric Regulatory Matters

For information concerning restructuring the electric utility industry in Delaware, Maryland, and Virginia, see Note 6 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II.

Electric Retail Rates

DPL's base rates for retail electric service are subject to the approval of the DPSC, MPSC, and VSCC. However, the utility ratemaking process is changing in Delaware, Maryland, and Virginia, as discussed in Note 6 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II.

See Note 6 to DPL's 1998 Consolidated Financial Statements, included in Part II, Item 8, for information concerning base rate decreases related to the Merger and base rate decreases expected in connection with the electric utility industry restructuring.

Electric Energy Adjustment Clauses

DPL's regulated retail electric tariffs include energy adjustment clauses that provide for collection from customers of fuel costs and the energy costs of purchased and net interchange power. Any under- or over-collection of energy adjustment clause costs in a current period is generally deferred until customers' rates are adjusted to collect or return the under- or over-collection. Capacity costs arising from purchased power transactions are generally subject to base rate recovery.

The current status or results of significant fuel rate issues are discussed below. As of December 31, 1998, DPL's accrued liabilities included amounts which are expected to adequately provide for disallowances of energy adjustment clause costs and penalties related to the issues discussed below.

Both Delaware and Maryland have programs that assess the overall performance of DPL's 15 major generating units. Under the DPSC's Power Plant Performance Program (PPPP), DPL can receive financial rewards or penalties, which will not exceed an estimated cap of $1.7 million in 1998. The 1996 and 1997 PPPP results were not material to DPL's financial position or results of operations. If DPL does not meet an overall system performance standard set by Maryland's Generating Unit Performance Program, the MPSC can disallow certain fuel costs of units that operated below their individual performance standards. DPL did not meet the 1996 or 1997 overall system standards due principally to the Salem outage. For information concerning replacement power costs not recovered through customer rates due to a prolonged outage at Salem, see Note 18 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II.

DPL's long-term purchased power agreement with PECO has previously been the subject of regulatory litigation in Delaware as the result of disallowances proposed by DPSC Staff and the Delaware Division of the Public Advocate. No such disallowances were ordered for 1996 or 1997. Delaware's Division of the Public Advocate has proposed a total disallowance of $17.7 million for 1998 and 1999. DPL will contest the proposed disallowance.

Energy adjustment clauses are expected to be eliminated under electric industry restructuring initiatives. Based on existing restructuring initiatives in Delaware, Maryland, and Virginia, profits or losses on the energy portion of electricity sales may affect DPL's earnings after restructuring becomes effective.

Gas Business

Deregulation

Effective April 1, 1996, a restructuring of natural gas pricing and service options enabled DPL's large and medium volume commercial and industrial customers to purchase gas from DPL, or directly from other suppliers and make arrangements for transporting gas purchased from these suppliers to their facilities. DPL's transportation customers pay a fee, which may be either fixed or negotiated, for the use of DPL's gas transmission and distribution facilities.

The restructuring mentioned above also authorized off-system gas sales and other "nonjurisdictional merchant sales and services." Earnings from gas sales which are off the Delmarva Peninsula and do not use DPL's gas system assets are not shared with regulated customers through lower rates. For other off-system gas sales and nonjurisdictional merchant sales and services, 80% of the margin (revenues net of fuel costs) earned reduces energy rates charged to firm gas customers.

On December 1, 1998, DPL filed an application with the DPSC, seeking approval of a pilot program to provide transportation service and a choice of gas suppliers to a group of retail customers. DPL proposed a one-year pilot program, starting November 1, 1999, open to 15% of residential customers and 15% of small commercial customers. DPL and intervening parties are engaged in settlement discussions about the proposed pilot program.

Gas Operations

DPL purchases gas supplies from marketers and producers under spot market, short-term, and long-term agreements. As shown in the table below, DPL's maximum 24-hour system capability, including natural gas purchases, storage deliveries, and the emergency sendout capability of its peak shaving plant, is 187,074 Mcf (thousand cubic feet).

	Number of Contracts	Expiration Dates	Daily Mcf
Supply	1	2001	9,180
Transportation	5	2004-2016	82,810
Storage	6	1999-2011	50,084
Local Peak Shaving (emergency capability)			45,000
Total			187,074

DPL experienced an all-time daily peak in combined firm sales and transportation sendout of 158,810 Mcf on January 17, 1997. DPL's peak shaving plant liquefies, stores, and re-gasifies natural gas in order to provide supplemental gas in the event of pipeline supply shortfalls or system emergencies.

Gas Regulatory Matters

Similar to DPL's Delaware electric energy adjustment clause, a gas cost rate clause provides for the recovery of gas costs from DPL's regulated gas customers. Gas costs for regulated, on-system customers are charged to operations based on costs billed to customers under the gas cost rate clause. Any under- or over-collection of gas costs in a current period is generally deferred until customers' rates are adjusted to collect or return the under- or over-collection.

In 1998, DPL implemented a DPSC-approved gas price hedging/risk management program with respect to gas supply for regulated customers. The program seeks to limit regulated customers exposure to commodity price uncertainty. Costs and benefits of the program are included in the gas cost rate clause, resulting in no effect on DPL's earnings.

Other Regulatory Matters

Special Contract Rate Tariffs

Under programs approved by the MPSC and DPSC, DPL may enter into negotiated contracts with retail electric customers in Maryland and retail electric and natural gas customers in Delaware. Also, "Real Time Pricing" (RTP) tariffs are available to customers in Maryland and in Delaware, and an experimental RTP tariff is effective in Virginia. The RTP tariffs provide additional flexibility in providing pricing and service to certain large customers.

Cost Accounting Manual/Code of Conduct

DPL has cost allocation and direct charging mechanisms in place to ensure that there is no cross-subsidization of competitive activities by regulated utility activities. In 1998, DPL made filings with the DPSC, the MPSC and VSCC to update and revise its Cost Accounting Manual (CAM) to reflect the holding company structure created in 1998. The CAM is subject to review and audit.

DPL is also subject to various Codes of Conduct that affect the relationship between DPL's regulated and Conectiv's competitive activities. In general, these Codes of Conduct limit information obtained through utility activities from being disseminated to employees engaged in non-regulated activities, require separate telephone numbers for competitive activities and restrict or prohibit sales leads, joint sales calls, or joint promotions.

Requirements that separate operational and managerial employees be maintained, as required by the MPSC for non-regulated activities making retail sales of electricity or gas, could impact the way DPL and the Conectiv system of companies are organized and DPL's ability to capture economies of common management and deploy personnel efficiently, without duplicating personnel functions. Prohibitions or restrictions on joint promotions may adversely impact Conectiv's competitive businesses.

Virginia Affiliates Act

Certain types of transactions between DPL and its affiliates may require the prior approval of the VSCC under the Virginia Affiliates Act. Past applications have generally been approved by the VSCC.

Federal Decontamination & Decommissioning Fund

The Energy Policy Act of 1992 provided for creation of a Decontamination & Decommissioning (D&D) Fund to pay for the future clean-up of DOE gaseous diffusion enrichment facilities. Domestic utilities and the federal government are required to make payments to the D&D Fund until 2008 or $2.25 billion, adjusted annually for inflation, is collected. The liability accrued for DPL's share of the D&D Fund was $5.3 million as of December 31, 1998. DPL is recovering this cost through energy adjustment clause revenues.

Capital Spending and Financing Program

For financial information concerning DPL's capital spending and financing program, refer to "Liquidity and Capital Resources" in the Management's Discussion and Analysis of Financial Condition and Results of Operations, included in Item 7, of Part II and Notes 12 to 14 to DPL's 1998 Consolidated Financial Statements, included in Item 8 of Part II.

DPL's ratios of earnings to fixed charges and earnings to fixed charges and preferred stock dividends under the SEC Methods for 1994-1998 are shown below.

	Year Ended December 31,				
	1998	1997	1996	1995	1994
Ratio of Earnings to Fixed Charges (SEC Method)	2.92	2.83	3.33	3.54	3.49
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends (SEC Method)	2.72	2.63	2.83	2.92	2.85

Under the SEC Method, earnings, including Allowance For Funds During Construction (AFUDC), have been computed by adding income taxes and fixed charges to net income. Fixed charges include gross interest expense, the estimated interest component of rentals, and dividends on preferred securities of a subsidiary trust. For the ratio of earnings to fixed charges and preferred stock dividends, preferred stock dividends represent annualized preferred stock dividend requirements multiplied by the ratio that pre-tax income bears to net income. Excluding the Merger-related pre-tax charge of $27.4 million discussed in Note 4 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II, the 1998 ratio of earnings to fixed charges was 3.21 and the 1998 ratio of earnings to fixed charges and preferred stock dividends was 2.98.

Environmental Matters

DPL is subject to various federal, regional, state, and local environmental regulations, including air and water quality control, oil pollution control, solid and hazardous waste disposal, and limitation on land use. Permits are required for DPL's construction projects and the operation of existing facilities. DPL has incurred, and expects to continue to incur, capital expenditures and operating costs because of environmental considerations and requirements. DPL has a continuing program to assure compliance with the environmental standards adopted by various regulatory authorities.

Included in DPL's forecasted capital requirements are construction expenditures for compliance with environmental regulations, which are estimated to be $10 million in 1999.

Air Quality Regulations

The federal Clean Air Act requires utilities and other industries to significantly reduce emissions of air pollutants such as sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). Title IV of the Clean Air Act, the acid rain provisions, established a two-phase program which mandated reductions of SO_2 and NO_x emissions from certain utility units by 1995 (Phase I) and required other utility units to begin reducing SO_2 and NO_x emissions in the year 2000 (Phase II). Phase I emission reductions requirements applicable to the jointly-owned Conemaugh Power Plant have been achieved. The remainder of DPL's wholly- and jointly-owned fossil-fuel units are expected to meet Phase II emission limits through a combination of fuel switching and SO_2 allowance trading.

DPL's facilities also must comply with Title I of the Clean Air Act, the ozone nonattainment provisions, which require states to promulgate Reasonably Available Control Technology (RACT) regulations for existing sources located within ozone nonattainment areas or within the Northeast Ozone Transport Region (NOTR). DPL's facilities in Delaware and Maryland are in the NOTR. To comply with RACT regulations, DPL has installed low NO_x burner technology on six of its generating units. DPL's RACT compliance program has not yet received final regulatory approvals by Delaware and Maryland.

Additional ''post-RACT'' NO_x emission regulations are being pursued by states in the NOTR. Delaware has proposed post-RACT NOx control regulations requiring attainment of summer seasonal emission reductions of up to 65% below 1990 levels by May 1999 through reduced emissions or the procurement of NO_x emission allowances. DPL's post-RACT compliance plan for its Delaware generating units includes capital expenditures of approximately $12 million.

In addition to the above requirements, summer seasonal NO_x controls commensurate with reductions of up to 85% below baseline years by the year 2003 are required for areas in the NOTR, which includes Delaware. DPL currently cannot determine the additional operating and capital costs that will be incurred to comply with these initiatives since state regulations implementing the federal requirement have not yet been promulgated.

In July 1997, the United States Environmental Protection Agency (USEPA) adopted new federal air quality standards for particulate matter and ozone. The new particulate matter standard addressed fine particulate matter. Attainment of the fine particulate matter standard may require reductions in NO_x and SO_2. However, under the time schedule announced by the USEPA, particulate matter non-attainment areas will not be designated until 2002 and control measures to meet this standard will not be identified until 2005.

Water Quality Regulations

The federal Water Pollution Control Act, as amended (the Clean Water Act) provides for the imposition of effluent limitations to regulate the discharge of pollutants, including heat, into the waters of the United States. National Pollution Discharge Elimination System (NPDES) permits issued by state environmental regulatory agencies specify effluent limitations, monitoring requirements, and special conditions with which facilities discharging wastewaters must comply. To ensure that water quality is maintained, permits are issued for a term of five years and are modified as necessary to reflect requirements of new or revised regulations or changes in facility operations.

The Clean Water Act also requires that cooling water intake structures be designed to minimize adverse environmental impact. The USEPA is required by a consent order to propose regulations in 1999 for determining whether cooling water intake structures represent the best technology available for minimizing adverse environmental impacts. Final action on the proposed regulations is required in 2001.

Between 1976 and 1979, DPL submitted to the Delaware Department of Natural Resources and Environmental Control (DNREC) the results of environmental impact studies which demonstrated compliance with the Clean Water Act. DNREC has required DPL to update its earlier studies to determine if the Indian River and Edge Moor power plants are still in compliance. In addition, in 1993 DNREC promulgated increased restrictions on thermal discharges. Studies assessing thermal water quality standards compliance will be completed in 1999 and studies assessing impacts of the cooling water intake structures will be completed in 2001. If the studies indicate an adverse environmental impact, then upgrades to the intake structures and/or environmental enhancement projects to offset adverse impacts will be required. Impact studies would cost up to $2 million per plant. Costs for intake structure upgrades and enhancement projects would range from approximately $1 million if little adverse impact is found, to $45 million if cooling towers are required, which DPL considers to be an unlikely potential outcome.

PSE&G is implementing the 1994 New Jersey Pollution Discharge Elimination System (NJPDES) permit issued for the jointly-owned Salem facility, which requires, among other things, water intake screen modifications and wetlands restoration. Under the 1994 permit, PSE&G is continuing to restore wetlands and conduct the requisite management and monitoring associated with the special conditions of the 1994 permit. In 1999, PSE&G must apply to renew Salem's NJPDES permit.

Hazardous Substances

The nature of the electric and gas utility businesses results in the production, or handling, of various by-products and substances which may contain substances defined as hazardous under federal or state statutes. The disposal of hazardous substances can result in costs to clean up facilities found to be contaminated due to past disposal practices. Federal and state statutes authorize governmental agencies to compel responsible parties to clean up certain abandoned or uncontrolled hazardous waste sites. DPL's exposure is minimized by adherence to environmental standards for DPL-owned facilities and through a waste disposal contractor screening and audit process.

As of December 31, 1998, DPL's other accrued liabilities included $2 million for clean-up and other potential costs related to federal and state superfund sites. DPL does not expect such future costs to have a material effect on DPL's financial position or results of operations. For additional information, see Note 19 to DPL's 1998 Consolidated Financial Statements included in Item 8 of Part II.

Executive Officers

The names, ages, and positions of all of the executive officers of DPL as of December 31, 1998, are listed below, along with their business experiences during the past five years. Officers are elected annually by Conectiv's Board of Directors. There are no family relationships among these officers, nor any arrangement or understanding between any officer and any other person pursuant to which the officer was selected.

Executive Officers of DPL
(As of December 31, 1998)

Name, Age and Position	Business Experience During Past 5 Years
Howard E. Cosgrove, 55 ..... Chairman of the Board and Chief Executive Officer	Elected 1998 as Chairman of the Board and Chief Executive Officer of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Elected 1992 as Chairman of the Board, President and Chief Executive Officer and Director of Delmarva Power & Light Company
Meredith I. Harlacher, Jr., 56 ..... President	Elected 1998 as President and Chief Operating Officer of Conectiv, and President and Chief Operating Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1993 as Senior Vice President of Atlantic Energy, Inc.
Barry R. Elson, 57 ..... Executive Vice President	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1997 as Executive Vice President, Delmarva Power & Light Company. Executive Vice President, Cox Communications, Inc., Atlanta, Georgia, from 1995 to 1996. Senior Vice President, Cox Enterprises/Cox Communications, Inc., Atlanta, Georgia, from 1984 to 1995.
Thomas S. Shaw, 51 ..... Executive Vice President	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1992 as Senior Vice President, Delmarva Power & Light Company.
Barbara S. Graham, 50 ..... Senior Vice President and Chief Financial Officer	Elected 1998 as Senior Vice President and Chief Financial Officer of Conectiv, and Senior Vice President and Chief Financial Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1994 as Senior Vice President, Treasurer and Chief Financial Officer, Delmarva Power & Light Company. Vice President and Chief Financial Officer from 1992 to 1994.
James P. Lavin, 51 ..... Controller and Chief Accounting Officer	Elected 1998 as Controller of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Elected 1993 as Comptroller, Delmarva Power & Light Company.
John C. van Roden, 49 ..... Senior Vice President and Chief Financial Officer*	Elected 1998 as Senior Vice President and Chief Financial Officer, effective January 1999, of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Principal, Cook and Belier, Inc. in 1998. Senior Vice President/Chief Financial Officer and Vice President/Treasurer, Lukens, Inc. from 1987 to 1998.

* Effective January 1999

Item 2. Properties

Substantially all utility plants and properties of DPL are subject to the lien of the Mortgage under which DPL's First Mortgage Bonds are issued.

DPL's electric properties are located in Delaware, Maryland, Virginia, Pennsylvania, and New Jersey. The following table sets forth the net installed summer electric generating capacity available to DPL to serve its peak load as of December 31, 1998.

Station	Location	Net Installed Capacity (kilowatts)
Coal-Fired		
Edge Moor	Wilmington, DE	260,000
Indian River	Millsboro, DE	767,000
Conemaugh	New Florence, PA	63,000(A)
Keystone	Shelocta, PA	63,000(A)
		1,153,000
Oil-Fired		
Edge Moor	Wilmington, DE	445,000
Vienna	Vienna, MD	153,000
		598,000
Combustion Turbines/Combined Cycle		
Hay Road	Wilmington, DE	511,000
Christiana	Wilmington, DE	45,000
Edge Moor	Wilmington, DE	13,000
Madison Street	Wilmington, DE	11,000
West	Marshallton, DE	15,000
Delaware City	Delaware City, DE	16,000
Indian River	Millsboro, DE	17,000
Vienna	Vienna, MD	17,000
Tasley	Tasley, VA	26,000
Salem	Lower Alloways Creek Twp., NJ	3,000(A)
		674,000
Nuclear		
Peach Bottom	Peach Bottom Twp., PA	164,000(A)
Salem	Lower Alloways Creek Twp., NJ	164,000(A)
		328,000
Diesel Units		
Crisfield	Crisfield, MD	10,000
Bayview	Bayview, VA	12,000
Keystone	Shelocta, PA	400(A)
Conemaugh	New Florence, PA	400(A)
		22,800
Customer-Owned Capacity	Delaware City, DE	57,000(B)
Long-Term Capacity Purchase		237,000
Subtotal		3,069,800
Short-Term Capacity Purchase		449,000
Total		3,518,800

(A) DPL's portion of jointly-owned plants.

(B) Represents capacity owned by a refinery customer which is available to DPL to serve its peak load.

DPL's electric transmission and distribution system includes 1,391 transmission poleline miles of overhead lines, 5 transmission cable miles of underground cables, 6,931 distribution poleline miles of overhead lines, and 5,540 distribution cable miles of underground cables.

DPL has a liquefied natural gas plant located in Wilmington, Delaware, with a storage capacity of 3.045 million gallons and an emergency sendout capability of 45,000 Mcf per day. DPL also owns four natural gas city gate stations at various locations in its gas service territory. These stations have a total sendout capacity of 125,000 Mcf per day.

The following table sets forth DPL's gas pipeline miles:

Transmission Mains	114*
Distribution Mains	1,492
Service Lines	1,104

* Includes 11 miles of joint-use gas pipeline that is used 10% for gas operations and 90% for electric operations.

DPL owns and occupies office buildings in Wilmington and Christiana, Delaware and Salisbury, Maryland, and also owns elsewhere in its service area a number of properties that are used for office, service, and other purposes.

Item 3. Legal Proceedings

See Note 18 to DPL's 1998 Consolidated Financial Statements included in Part II, Item 8 for information concerning DPL's lawsuit against Westinghouse Electric Corporation, the designer and manufacturer of the Salem steam generators.

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

No matter was submitted during the fourth quarter of the fiscal year covered by this report to a vote of security holders, through the solicitation of proxies or otherwise.

DELMARVA POWER & LIGHT COMPANY

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

All shares of DPL's common stock are owned by Conectiv, its parent company.

DPL's certificate of incorporation requires payment of all preferred dividends in arrears (if any) prior to payment of common dividends to Conectiv, and has certain other limitations on the payment of common dividends.

DELMARVA POWER & LIGHT COMPANY

Item 6. Selected Financial Data

	Year Ended December 31,				
	1998(1)	1997	1996	1995	1994
	(Dollars in Thousands, Except Per Share Amounts)				
Operating Results and Data					
Operating Revenues	$ 1,899,899	$ 1,415,367	$ 1,168,664	$ 1,055,725	$ 1,033,442
Operating Income	$ 265,427 (2)	$ 226,294	$ 250,389	$ 254,425	$ 233,244 (3)
Net Income	$ 112,410 (2)	$ 105,709	$ 116,187	$ 117,488	$ 108,310 (3)
Earnings Applicable to Common Stock	$ 108,058 (2)	$ 101,218	$ 107,251	$ 107,546	$ 98,940 (3)
On System Electric Sales (kWh 000) (4)	13,429,102	13,231,766	12,925,716	12,310,921	12,505,082
On System Gas Sold and Transported (Mcf 000)	21,587	22,855	22,424	21,371	20,342
Capitalization					
Variable Rate Demand Bonds (VRDB) (5)	$ 71,500	$ 71,500	$ 85,000	$ 86,500	$ 71,500
Long-Term Debt	951,911	983,672	904,033	853,904	774,558
DPL Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely DPL Debentures	70,000	70,000	70,000	—	—
Preferred Stock	89,703	89,703	89,703	168,085	168,085
Common Stockholder's Equity	851,494	954,496	934,913	923,440	884,169
Total Capitalization with VRDB	$ 2,034,608	$ 2,169,371	$ 2,083,649	$ 2,031,929	$ 1,898,312
Other Information					
Total Assets	$ 2,904,851	$ 3,015,481	$ 2,931,855	$ 2,866,685	$ 2,669,785
Long-Term Capital Lease Obligations	$ 17,003	$ 19,877	$ 20,552	$ 20,768	$ 19,660
Capital Expenditures	$ 114,663	$ 156,808	$ 165,595	$ 142,833	$ 166,938
Common Dividends Declared (6)	$ 94,860	$ 94,065	$ 93,294	$ 92,686	$ 91,436

(1) As discussed in Note 4 to the Consolidated Financial Statements, Delmarva Power & Light Company (DPL) and Atlantic City Electric Company (ACE) became wholly-owned subsidiaries of Conectiv (the Merger) on March 1, 1998. The Merger also resulted in Conectiv owning the nonutility subsidiaries previously owned by DPL. Accordingly, the 1998 Consolidated Statement of Income includes 2 months of operating results for DPL's former nonutility subsidiaries.

(2) Employee separation and other Merger-related costs in 1998 decreased operating income and net income by $27.4 million and $16.6 million, respectively.

(3) An early retirement offer in 1994 decreased operating income and net income by $17.5 million and $10.7 million, respectively.

(4) Excludes interchange deliveries.

(5) Although Variable Rate Demand Bonds are classified as current liabilities, DPL intends to use the bonds as a source of long-term financing as discussed in Note 14 to the Consolidated Financial Statements.

(6) Amounts shown as total, rather than on a per-share basis, since DPL is a wholly-owned subsidiary of Conectiv. Excludes non-cash dividend for transfer of nonutility subsidiaries to Conectiv on March 1, 1998, due to the Merger.

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

Merger with Atlantic

On March 1, 1998, Delmarva Power & Light Company (DPL) and Atlantic City Electric Company (ACE) became wholly-owned subsidiaries of Conectiv, a registered holding company under the Public Utility Holding Company of 1935. Each outstanding share of DPL's common stock was exchanged for one share of Conectiv's common stock.

Conectiv became the owner of DPL's nonutility subsidiaries as of March 1, 1998, resulting in inclusion of two months of nonutility subsidiary operations in DPL's 1998 Consolidated Statement of Income. The Consolidated Statements of Income include revenues of $19.5 million and $113.0 million, and a net loss of $3.5 million and net income of $9.8 million, for 1998 and 1997, respectively, from the operations of these nonutility subsidiaries. The common stockholder's equity of these nonutility subsidiaries was $123.4 million as of February 28, 1998.

DPL continued to sell electricity and gas in markets not subject to price regulation subsequent to the Merger.

See Note 4 to the Consolidated Financial Statements for additional information concerning the Merger.

Earnings Results Summary

DPL had earnings applicable to common stock of $108.1 million and $101.2 million for 1998 and 1997, respectively. The $6.9 million earnings increase was reduced by a $16.6 million after-tax charge for costs associated with the Merger and a $13.3 million decrease in nonutility subsidiary earnings. In 1997, nonutility subsidiary earnings included a $13.7 million gain on the sale of a landfill and waste-hauling company. Excluding the one-time Merger costs and operating results of the nonutility subsidiaries, earnings were up $36.8 million in 1998. This increase was primarily due to a 2.5% retail electric kilowatt-hour (kWh) sales increase and lower operation and maintenance expenses. The earnings increase was constrained by milder winter weather's unfavorable effect on electric and gas sales.

Earnings applicable to common stock, for 1997, were $101.2 million, a $6.1 million decrease from 1996. The $6.1 million decrease was primarily attributed to losses from investments in new businesses and participation in the competitive energy markets (including branding expenditures), partly offset by the gain on the sale of the landfill and waste-hauling company. Regulated utility earnings were relatively flat in 1997 primarily because higher net electric revenues and lower outage expenses for the Salem nuclear generating units were offset by anticipated higher capital costs.

Electric Utility Industry Restructuring

As discussed on the following pages, deregulation of the electric utility industry is underway in Delaware, Maryland, and Virginia. Generally, with restructuring, the supply component of the price charged to a customer for electricity will be deregulated, and electricity suppliers will compete to supply electricity to customers. Customers would continue to pay the local utility a regulated price for the delivery of the electricity over the transmission and distribution system.

Stranded costs are costs which may not be recoverable in a competitive energy supply market due to lower prices or customers choosing a different supplier. Stranded costs generally include above-market costs associated with generation facilities or long-term purchased power agreements, and regulatory assets. DPL has quantified stranded costs in its Maryland regulatory filing and has proposed a plan seeking approval for recovery of these costs from customers during the transition to a competitive market.

When a specific plan that deregulates electricity supply becomes final, DPL would cease applying Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," to its electricity supply business in the regulatory jurisdiction to which the plan applies. To the extent that a deregulation plan provides for recovery of stranded costs through cash flows from the regulated transmission and distribution business, the stranded costs would continue to be recognized as assets under SFAS No. 71. Any stranded costs (including regulatory assets) for which cost recovery is not provided would be expensed.

The amount of stranded costs ultimately recovered from utility customers, if any, and the full impact of legislation deregulating the electric utility industry in any of the jurisdictions in which DPL operates cannot be predicted. Also, the quantification of stranded costs under existing generally accepted accounting principles (GAAP) differs from methods used in regulatory filings. Among other differences, GAAP precludes recognition of the gains on plants (or purchased power contracts) not impaired, but requires write down of the plants that are impaired. Due to these considerations, market conditions, timing, and other factors, DPL's management currently cannot predict the ultimate effects that electric utility industry deregulation may have on the financial statements of DPL, although deregulation may have a material adverse effect on DPL's results of operations.

Delaware

The Alliance for Fair Electric Competition Today, which includes DPL, worked with Delaware executive branch representatives and representatives of the Delaware Public Service Commission (DPSC) Staff to develop consensus restructuring legislation. House Bill No. 10, with several amendments, passed the Delaware House of Representatives, and the Delaware Senate. The Governor of Delaware is expected to sign the legislation.

House Bill No. 10 would allow DPL's Delaware customers to choose their electricity suppliers beginning on October 1, 1999 (for customers with peak demands of 1,000 kilowatts or more), January 15, 2000 (for customers with peak demands of 300 kilowatts or more), and 18 months after the legislation is enacted (for all other customers). House Bill No. 10 also provides for a residential rate reduction of 7.5% beginning October 1, 1999. Thereafter, except for a deferred fuel balance "true-up" and increases for extraordinary costs, residential rates may not be changed for four years; rates for customers in commercial and industrial rate classes may not be changed for three years. Under House Bill No. 10, certain low-income energy assistance and environmental programs are funded at an annual level of about $1.6 million by a charge in electric rates.

Among other matters, unbundled rates to be charged by DPL during these "rate freeze" periods have been agreed upon by a number of participants in the restructuring plan proceeding contemplated by House Bill No. 10. Included within the agreement on unbundled rates, DPL would recover $16 million (Delaware retail basis) of stranded costs, and electric rates would not be changed in the event DPL sells or transfers generating assets.

Maryland

In 1997, the Maryland Public Service Commission (MPSC) issued two orders which provide for retail electric competition to begin July 3, 2000, and be phased-in over a three-year period (one-third of the customers per year). Enabling legislation and resolution of complex issues such as stranded costs and utility taxation will be necessary for implementation of retail competition in Maryland.

On July 1, 1998, DPL filed with the MPSC its quantification of stranded costs and computation of unbundled rates, which are being considered in Case No. 8795. Stranded costs were estimated to be $217 million on a DPL system-wide basis ($69 million Maryland retail portion), including $123 million attributable to generating units, $54 million associated with purchased power contracts, $21 million related to fuel inventory financing costs, and $19 million of regulatory assets. DPL proposed full recovery of the Maryland portion of the stranded costs over a three-year period, starting with the commencement of retail competition on July 3, 2000.

The MPSC Staff and other parties contend that the market value of DPL's generating assets exceeds their book value and thus that DPL has negative stranded costs, or so-called "stranded benefits." Proposals for rate

reductions based on a sharing of these alleged benefits and other factors have been submitted to the MPSC in Case No. 8795. The proposed rate reductions vary widely, from 3% up to levels which, if adopted, would have a material adverse impact on DPL's results of operations.

Maryland's electric utilities, including DPL, continue to meet with the MPSC Staff and others to develop consensus enabling restructuring and related tax legislation for possible passage in the 1999 legislative session.

The MPSC is expected to issue its order on DPL's stranded cost recovery and unbundled rates by October 1, 1999.

Virginia

Comprehensive electric utility restructuring legislation has been introduced in the Virginia General Assembly. Senate Bill No. 1269 and identical House Bill No. 2615, introduced on January 21, 1999, were drafted by a joint House-Senate study committee created in 1996 to consider restructuring issues. Significant provisions of these Bills provide for:

- Phase-in of retail electric competition beginning January 1, 2002
- Rates in effect on January 1, 2001 to become "capped rates" to continue in effect through July 1, 2007, except for adjustments for changes in fuel costs and state tax rates
- Customers choosing an electricity supplier other than their incumbent utility continue to pay capped transmission and distribution rates but, instead of the capped generation rate, they would pay a "wires" charge which would be the difference between the capped generation rate and projected market prices for electricity
- Just and reasonable net stranded costs, are to be recovered through capped rates and wires charges during the period January 1, 2001 through July 1, 2007

Price Regulation of Energy Revenues

Through 1998, customer rates for non-energy costs have been established in past base rate proceedings before utility regulatory commissions. Changes in non-energy (or base rate) revenues due to volume, or rate changes, generally affect the earnings of DPL.

Energy costs, including fuel and purchased energy, are currently billed to rate-regulated customers under regulated energy adjustment clause rates. These energy rates are adjusted periodically for cost changes and are subject to review by regulatory commissions. "Energy revenues," or energy costs billed to customers, do not generally affect net income, because the amount of under- or over-recovered energy costs is generally deferred until it is subsequently recovered from or returned to utility customers.

Energy adjustment clauses are expected to be eliminated under electric utility industry restructuring initiatives. Based on existing restructuring initiatives, profits or losses on the energy portion of electricity sales may affect DPL's earnings, after restructuring becomes effective.

Electric revenues also include interchange delivery revenues, which result primarily from the sale of electricity to other electricity suppliers in the Pennsylvania-New Jersey-Maryland Interconnection (PJM Interconnection), which is an electric power pool. Interchange delivery revenues are currently reflected in the calculation of rates charged to customers under energy adjustment clauses and, thus, do not affect net income. Margins from interchange delivery revenues may impact earnings after deregulation due to elimination of energy adjustment clauses.

Revenues are also earned from sales not subject to price regulation. These sales include off-system bulk commodity sales and retail energy sales.

Electric Revenues and Sales

DPL's sources of electric revenues as a percentage of total electric revenues are shown in the table below. The percentage of DPL's consolidated electric revenues earned from sales not subject to price regulation has increased as DPL's participation in unregulated electricity markets has grown. Gross margin percentages earned in markets not subject to price regulation are generally lower than the gross margin percentages earned in regulated retail markets due to product differences, greater volume per customer, and unregulated pricing. However, incremental amounts of gross margin earned from sales not subject to price regulation enhance DPL's profitability.

Sources of Consolidated Electric Revenues

	1998	1997	1996
Regulated retail revenues	66.9%	81.0%	85.7%
Resale revenues	5.0%	6.3%	6.7%
Interchange delivery revenues	7.5%	3.3%	7.6%
Revenues from sales not subject to price regulation	20.6%	9.4%	—

Details of the changes in the various components of electric revenues are shown below.

Comparative Increase (Decrease) from Prior Year in Electric Revenues

	1998	1997
	(Dollars in Millions)	
Retail and Resale Revenues		
Non-Energy (Base Rate) Revenues	$ 18.4	$ 8.9
Energy Revenues	(16.1)	32.7
Interchange Delivery Revenues	62.8	(38.8)
Revenues from sales not subject to price regulation	172.1	102.4
	$237.2	$105.2

Non-energy revenues increased $18.4 million in 1998 primarily due to a 2.5% retail kWh sales increase which was attributed to favorable economic conditions and 1.6% customer growth. The retail kWh sales increase was reduced by milder winter weather's unfavorable effect on residential heating sales. The increase in non-energy electric revenues in 1998 was reduced by $10.7 million due to Merger-related customer base rate decreases.

For 1997 compared to 1996, electric non-energy revenues increased $8.9 million due to a 2.6% retail kWh sales increase, mainly attributed to favorable economic conditions and a 1.4% increase in the number of regulated retail customers. Milder weather limited the sales increase.

In 1998 and 1997, revenues from electric sales not subject to price regulation increased $172.1 million and $102.4 million, respectively, mainly because DPL sold more output off-system through the Merchant business. DPL actively participates in the wholesale energy markets to support wholesale utility and competitive retail marketing activities. Energy market participation results in exposure to commodity market risk when, at times, net open energy commodity positions are created or allowed to continue. To the extent that DPL has net open positions, controls are in place that are intended to keep risk exposures within certain management approved risk tolerance levels.

As discussed under "Price Regulation of Energy Revenues," energy and interchange delivery revenues generally do not affect net income

Electric Resale Business

The ability of electric resale customers to choose their electric supplier has created a competitive electric resale market. If an electric resale customer selects a supplier other than the local utility, then the local utility receives a fee for delivering the electricity to the resale customer. DPL's contract with its largest electric resale customer, Old Dominion Electric Cooperative (ODEC), is discussed below. Other electric resale customers of DPL have electricity supply contracts with DPL which expire in 2001 to 2004.

Under notice provisions in its electricity supply contract, ODEC reduced its load by 60 megawatts (MW) on September 1, 1998, from approximately 200 MW to 140 MW. ODEC has also notified DPL that it will reduce its load to zero on September 1, 2001. The annualized reduction in DPL's net income expected to result from ODEC's 60 MW load reduction is approximately $2 to $3 million. If ODEC further reduces its load to zero on September 1, 2001, then annualized net income would decrease by approximately an additional $7 to $8 million. These projected earnings decreases are net of the expected savings from avoided capacity costs.

Gas Revenues, Sales and Transportation

DPL earns gas revenues from on-system sales which generally are subject to price regulation, off-system sales which are not subject to price regulation, and from the transportation of gas for customers. Transportation customers may purchase gas from DPL or other suppliers.

Details of the changes in the various components of gas revenues are shown below.

Comparative Increase (Decrease) from Prior Year in Gas Revenues

	1998	1997
	(Dollars in Millions)	
Non-Energy (Base Rate) Revenues	$ (4.0)	$ (1.2)
Energy Revenues	(6.0)	8.8
Revenues from sales not subject to price regulation	341.0	82.2
	$331.0	$89.8

As shown in the above table, total gas revenues increased $331.0 million in 1998 and $89.8 million in 1997 primarily due to higher volumes of gas sold in markets not subject to price regulation. The margin earned from non-price regulated gas sales in excess of related purchased gas costs is relatively small due to the competitive nature of bulk commodity sales.

The decreases in non-energy (base rate) gas revenues for 1998 and 1997 were primarily due to milder weather during the heating seasons of both years, which resulted in lower residential gas sales (based on cubic feet sold) of 13.2% and 9.8%, respectively. The weather-related gas revenue decrease was partly offset by additional gas revenues from new customers. The number of regulated gas customers served increased 2.4% in 1998 and 2.3% in 1997.

As discussed under "Price Regulation of Energy Revenues," energy revenues generally do not affect net income.

Other Services Revenues

Other service revenues were comprised of the following:

	1998	1997	1996
	(Dollars in millions)		
HVAC (1)	$14.6	$ 62.8	$ 7.1
Operation of power plants	2.9	23.5	21.5
Landfill and waste hauling	—	12.7	14.1
Other (2)	17.9	20.2	24.8
Total	$35.4	$119.2	$67.5

(1) Heating, ventilation, and air conditioning (HVAC).

(2) Other includes real estate activities, value-added (energy-related) services, leveraged leasing, telecommunications and other miscellaneous services.

Total revenues from "Other Services" decreased $83.8 million in 1998, primarily due to the transfer of DPL's nonutility subsidiaries to Conectiv on March 1, 1998, and the loss of revenue attributed to the sale of a landfill and waste-hauling operation in the fourth quarter of 1997.

In 1997, other services revenues increased to $119.2 million from $67.5 million in 1996, mainly due to HVAC business acquisitions.

Electric Fuel and Purchased Energy Expenses

In 1998, electric fuel and purchased energy increased $204.4 million compared to 1997 primarily due to more energy supplied for greater volumes of electricity sold off-system and within DPL's service territory. In 1997, electric fuel and purchased energy expenses increased $89.2 million compared to 1996 primarily due to greater volumes of energy sold off-system and lower amounts of energy expenses deferred under energy adjustment clauses.

For information concerning the Salem outage's impact on electric fuel and purchased energy expenses, see Note 18 to the Consolidated Financial Statements.

The kWh output required to serve load within DPL's service territory is substantially equivalent to total output less interchange deliveries and off-system sales. In 1998, DPL's output for load within its service territory was provided by 34% coal generation, 32% net purchased power, 18% oil and gas generation, and 16% nuclear generation.

Gas Purchased

Primarily due to larger volumes of gas purchased for resale off-system, gas purchased increased $333.4 million in 1998 and $91.8 million in 1997.

Other Services' Cost of Sales

Other services' cost of sales decreased $59.1 million in 1998 primarily due to the transfer of DPL's nonutility subsidiaries to Conectiv on March 1, 1998, and the sale of a landfill and waste-hauling operation in the fourth quarter of 1997. Other services' cost of sales increased by $29.9 million in 1997 primarily due to acquisitions of HVAC service companies.

Purchased Electric Capacity

Purchased electric capacity costs increased $10.3 million in 1998 due to a greater capacity obligation to the PJM Interconnection and a higher average cost per megawatt of purchased capacity.

Operation and Maintenance Expenses

Operation and maintenance expenses decreased to $264.6 million in 1998 from $331.8 million in 1997. The $67.2 million decrease was primarily due to fewer employees, the transfer of the nonutility subsidiaries to Conectiv on March 1, 1998, and the absence of last year's re-start activities at the Salem nuclear power plant.

In 1997 operation and maintenance expenses increased $53.9 million mainly due to the start-up of the HVAC, telecommunications, retail energy, and merchant businesses, and costs associated with establishing the Conectiv brand name and gaining new customers. Lower pension cost and Salem outage expenses mitigated the total increase in operation and maintenance expenses.

Depreciation Expense

Depreciation expense decreased $4.4 million in 1998 due to the transfer of the nonutility subsidiaries to Conectiv on March 1, 1998, and the sale of a landfill and waste-hauling operation in the fourth quarter of 1997. These decreases were partially offset by higher utility depreciation expenses due to the completion of on-going construction projects. Depreciation expense increased $7.8 million in 1997 due to completion of on-going construction projects and installation of new systems.

Other Income

Other Income includes amounts for the nonutility subsidiaries transferred to Conectiv of $0.1 million in 1998, $33.3 million in 1997, and $8.9 million in 1996. Other income for 1997 includes a $22.9 million pre-tax gain on the sale of the Pine Grove landfill and related waste-hauling operations.

Financing Costs

Financing costs reflected in the consolidated income statement include interest charges, allowance for funds used during construction (AFUDC), dividends on preferred securities of a subsidiary trust, and dividends on preferred stock. Financing costs decreased $0.8 million in 1998 and increased $9.9 million in 1997. The increase for 1997 was mainly due to long-term financing requirements associated with DPL's utility business.

Year 2000

The Year 2000 issue is the result of computer programs and embedded systems using a two-digit format, as opposed to four digits, to indicate the year. Computer and embedded systems with this characteristic may be unable to interpret dates during and beyond the year 1999, which could cause a system failure or other computer errors, leading to disruption of operations. A project team, originally started in 1996 by ACE, is assisting line management in addressing the issue of computer programs and embedded systems not properly recognizing the Year 2000. A Conectiv corporate officer, reporting directly to the Chief Executive Officer, is coordinating all Year 2000 activities. There are substantial challenges in identifying and correcting the many computer and embedded systems critical to generating and delivering power, delivering natural gas and providing other services to customers.

The project team is using a phased approach to managing its activities. The first phase is inventory and assessment of all systems, equipment, and processes. Each identified item is given a criticality rating of high, medium or low. Those items rated as high or medium are then subject to the second phase of the project. The second phase is determining and implementing corrective action for the systems, equipment and processes, and concludes with a test of the unit being remediated. The third phase is system testing and compliance certification. Additionally, the project team will be updating existing outage contingency plans to address Year 2000 issues.

Overall, Conectiv's Year 2000 Project covers approximately 140 different systems (some with numerous components) that had been originally identified as high or medium in criticality. However, only 21 of those 140 systems are essential for Conectiv to provide electric and gas service to its customers. The Year 2000 Project team will be focusing on these 21 systems, with additional work on the other systems continuing based on their relative importance to Conectiv's businesses.

The following chart sets forth the current estimated completion percentage of the 140 different systems in the Year 2000 Project by major business group, and for the information technology systems used in managing Conectiv's business. Conectiv expects significant progress in remediation and testing over the next quarter based on work that is in process and material that is being ordered.

Business Group	Inventory and Assessment	Corrective Action/ Unit Testing	System Testing/ Compliance
Business systems	95%	85%	65%
Power production	95%	30%	30%
Electricity distribution	95%	10%	5%
Gas delivery	95%	60%	60%
Competitive services	90%-95%	30%-80%	30%-80%

DPL is also contacting vendors and service providers to review remediation of their Year 2000 issues. Many aspects of DPL's businesses are dependent on third parties. For example, fuel suppliers must be able to provide coal or gas to allow DPL to generate electricity.

Distribution of electricity is dependent on the overall reliability of the electric grid. DPL is cooperating with the North American Electric Reliability Council (NERC) and the PJM Interconnection in Year 2000 remediation and remediation planning efforts, and has accelerated its Year 2000 Project timeline to be generally in-line with the recommendations of those groups. At this time, a few generating units are scheduled for remediation and testing in September to coincide with previously scheduled outages. Recent reports issued by NERC indicate a diminished risk of disruption to the electric grid caused by Year 2000 issues.

Conectiv has incurred approximately $3 million in costs for the Year 2000 Project. Current estimates of the costs for the Year 2000 Project range from $10 million to $15 million. These estimates could change significantly as the Year 2000 Project progresses. The costs set forth above do not include several significant expenditures covering new systems, such as Conectiv's SAP business, financial and human resources management system and an Energy Control System. While the introduction of these new systems effectively remediated Year 2000 problems in the systems they replaced, Conectiv has not previously reported the expenditures on these systems in its costs for the Year 2000 Project.

Since the project team is still in the process of assessing and correcting impacted systems, equipment and processes, DPL cannot with certainty determine whether the Year 2000 issue might cause disruptions to its operations and have impacts on related costs and revenues. DPL assesses the status of the Year 2000 Project on at least a monthly basis to determine the likelihood of business disruptions. Based on its own Year 2000 program, as well as reports from NERC and other utilities, DPL's management believes it is unlikely that significant Year 2000 related disruptions will occur. However, any substantial disruption to DPL's operations could negatively impact DPL's revenues, significantly impact its customers and could generate legal claims against DPL. DPL's results of operations and financial position would likely suffer an adverse impact if other entities, such as suppliers, customers and service providers do not effectively address their Year 2000 issues.

Liquidity and Capital Resources

DPL's primary sources of capital are internally generated funds (net cash provided by operating activities less common and preferred dividends) and external financings. These resources provide capital for utility construction expenditures and other capital requirements, such as repayment of debt and capital lease obligations. In the foreseeable future, DPL expects that incremental demand for electricity will be supplied with purchased power.

Net cash inflows from operating activities increased to $246.2 million in 1998 from $221.3 million in 1997, mainly due to lower operation and maintenance expenses and higher electric revenues, net of amounts paid for electric fuel and purchased energy. Cash inflows from operating activities in 1997 remained at about the same level as in 1996. In 1997, cash used by new businesses offset higher cash flows from regulated energy revenues, net of amounts paid for energy.

Capital expenditures decreased $42.1 million in 1998 and $8.8 million in 1997. The 1998 decrease was primarily due to the transfer of the nonutility subsidiaries to Conectiv on March 1, 1998, and lower utility construction expenditures. The 1997 decrease was principally due to a $40.5 million decrease in utility construction expenditures, partly offset by $35.2 million of capital expenditures for expansion of Conectiv Communications, Inc.'s fiber optic network.

DPL's cash expenditures for business acquisitions of $9.0 million, $32.0 million, and $8.3 million, in 1998, 1997, and 1996, respectively, were primarily due to the acquisition of HVAC and related businesses and direct Merger costs.

After deducting common and preferred dividend payments of $99.2 million in 1998, $98.0 million in 1997, and $102.4 million in 1996, internally generated funds were $147.0 million in 1998, $123.2 million in 1997, and $120.3 million in 1996. Internally generated funds provided 129%, 107%, and 77% of the cash required for utility construction in 1998, 1997, and 1996, respectively.

"Sales of nonutility assets" under cash flows from investing activities includes $33.4 million of pre-tax proceeds from the 1997 sale of Pine Grove Inc.'s landfill and waste-hauling operations.

During 1996-1998, short-term debt used $43.1 million of funds, and long-term financing activities (debt, preferred equity, and common equity) provided net cash of $128.9 million ($287.5 million of issuances net of $158.6 million of redemptions).

Long-term debt issued during 1996 to 1998 amounted to $199.2 million, which consisted entirely of Medium Term Notes with interest rates ranging from 6.6% to 7.72% and maturities ranging from 5 to 30 years. Redemptions of long-term debt during 1996 to 1998 amounted to $62.2 million, which included $25.0 million of 5.69% Medium Term Notes, $25.0 million of 6 3/8% First Mortgage Bonds, and $12.2 million of other debt.

Scheduled maturities of long-term debt over the next five years are as follows: 1999—$31.3 million; 2000—$1.5 million; 2001—$2.3 million; 2002—$48.1 million; 2003—$92.3 million.

In October 1996, a subsidiary trust of DPL issued $70.0 million of 8.125% DPL obligated mandatorily redeemable preferred securities and loaned the proceeds to DPL. On a consolidated basis, these preferred securities provide a tax benefit equivalent to the tax effect of a deduction for distributions on the preferred securities. The proceeds from issuance of the preferred securities and additional short-term debt were used to retire $78.4 million of DPL's preferred stock, which had an average dividend rate of 6.9%.

DPL's capital structure as of December 31, 1998 and 1997, expressed as a percentage of total capitalization is shown below.

	1998	1997
Long-term debt and variable rate demand bonds	50.3%	48.6%
Preferred stock and securities	7.8%	7.4%
Common stockholder's equity	41.9%	44.0%

DPL's estimated requirements during 1999 for capital expenditures are $138 million. The uncertainty of the impact of electric utility industry restructuring, and the extent to which DPL retains or divests certain of its assets, including generating plants, will affect the ultimate amount of capital expenditures and the amount of external funds required in excess of internally generated funds. DPL's management expects that external funds will be derived from the sale of long-term debt, as required.

Quantitative and Qualitative Disclosures About Market Risks

The following discussion contains "forward looking statements." These projected results have been prepared based upon certain assumptions considered reasonable given the information currently available to

DPL. Nevertheless, because of the inherent unpredictability of interest rates, equity market prices, and energy commodity prices as well as other factors, actual results could differ materially from those projected in such forward-looking information. For a description of DPL's significant accounting policies associated with these activities see Notes 1 and 7 to the Consolidated Financial Statements.

Interest Rate Risk

DPL is subject to the risk of fluctuating interest rates in the normal course of business. DPL manages interest rates through the use of fixed and, to a lesser extent, variable rate debt. As of December 31, 1998, a hypothetical 10% change in interest rates would result in a $0.4 million change in interest costs and earnings before taxes related to short-term and variable rate debt.

Equity Price Risk

DPL maintains a trust fund, as required by the Nuclear Regulatory Commission, to fund certain costs of nuclear decommissioning (See Note 8 to the Consolidated Financial Statements). The funds are invested primarily in domestic and international equity securities, fixed-rate, fixed income securities, and cash and cash equivalents. By maintaining a portfolio that includes long-term equity investments, DPL is maximizing the returns to be utilized to fund nuclear decommissioning costs. However, the equity securities included in DPL's portfolio are exposed to price fluctuations in equity markets, and the fixed-rate, fixed income securities are exposed to changes in interest rates. DPL actively monitors its portfolios by benchmarking the performance of its investments against certain indexes and by maintaining, and periodically reviewing, established target asset allocation percentages of the assets in its trust. Because the accounting for nuclear decommissioning recognizes that costs are recovered through electric rates, fluctuations in equity prices and interest rates, while affecting the carrying value of the invesments, are offset by the effects of regulation and therefore do not affect the earnings of DPL.

Commodity Price Risk

DPL is exposed to the impact of market fluctuations in the price and transportation costs of natural gas and electricity. DPL engages in commodity hedging activities to minimize the risk of market fluctuations associated with the purchase and sale of energy commodities (natural gas and electricity). Some hedging activities are conducted using energy derivatives (futures, option, and swaps). The remainder of DPL's hedging activity is conducted by backing physical transactions with offsetting physical positions. The hedging objectives include the assurance of stable and known minimum cash flows and the fixing of favorable prices and margins when they become available. DPL also engages in energy commodity trading and arbitrage activities, which expose DPL to commodity market risk when, at times, DPL creates net open energy commodity positions or allows net open positions to continue. To the extent that DPL has net open positions, controls are in place that are intended to keep risk exposures within management-approved risk tolerance levels.

DPL uses a value-at-risk model to assess the market risk of its electricity and gas commodity activities. The model includes fixed price sales commitments, physical forward contracts, and commodity derivative instruments. Value at risk represents the potential gain or loss on instruments or portfolios due to changes in market factors, for a specified time period and confidence level. DPL estimates value-at-risk across its power and gas commodity business using a delta-normal variance/covariance model with a 95 percent confidence level and assuming a five-day holding period. At December 31, 1998, DPL's calculated value at risk with respect to its commodity price exposure was approximately $0.6 million.

Forward-Looking Statements

The Private Securities Litigation Reform Act of 1995 (Litigation Reform Act) provides a ''safe harbor'' for forward-looking statements to encourage such disclosures without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements

identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been made in this report. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "will," "anticipate," "estimate," "expect," "objective," and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following: deregulation and the unbundling of energy supplies and services; an increasingly competitive energy marketplace; sales retention and growth; federal and state regulatory actions; future litigation results; costs of construction; operating restrictions; increased costs and construction delays attributable to environmental regulations; nuclear decommissioning and the availability of reprocessing and storage facilities for spent nuclear fuel; and credit market concerns. DPL undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors pursuant to the Litigation Reform Act should not be construed as exhaustive or as any admission regarding the adequacy of disclosures made by DPL prior to the effective date of the Litigation Reform Act.

DELMARVA POWER & LIGHT COMPANY

Item 8. Financial Statements and Supplementary Data

REPORT OF MANAGEMENT

Management is responsible for the information and representations contained in the consolidated financial statements of Delmarva Power & Light Company (DPL). Our consolidated financial statements have been prepared in conformity with generally accepted accounting principles, based upon currently available facts and circumstances and management's best estimates and judgments of the expected effects of events and transactions.

DPL and its subsidiary companies maintain a system of internal controls designed to provide reasonable, but not absolute, assurance of the reliability of the financial records and the protection of assets. The internal control system is supported by written administrative policies, a program of internal audits, and procedures to assure the selection and training of qualified personnel.

PricewaterhouseCoopers LLP, independent accountants, are engaged to audit the financial statements and express their opinion thereon. Their audits are conducted in accordance with generally accepted auditing standards which include a review of selected internal controls to determine the nature, timing, and extent of audit tests to be applied.

Conectiv's Audit Committee of the Board of Directors, composed of outside directors only, meets with management, internal auditors, and independent accountants to review accounting, auditing, and financial reporting matters. The independent accountants are appointed by the Board on recommendation of the Audit Committee, subject to stockholder approval.

/s/ HOWARD E. COSGROVE

Howard E. Cosgrove
Chairman of the Board
and Chief Executive Officer

/s/ JOHN C. VAN RODEN

John C. van Roden
Senior Vice President
and Chief Financial Officer

February 5, 1999

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
Delmarva Power & Light Company
Wilmington, Delaware

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, changes in common stockholder's equity and of cash flows present fairly, in all material respects, the financial position of Delmarva Power & Light Company (DPL) and subsidiary companies as of December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. These financial statements are the responsibility of DPL's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP
2400 Eleven Penn Center
Philadelphia, Pennsylvania
February 5, 1999

DELMARVA POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	1998	1997	1996
	(Dollars in Thousands)		
Operating Revenues			
Electric	$1,329,393	$1,092,144	$ 986,921
Gas	535,082	204,057	114,284
Other services	35,424	119,166	67,459
	1,899,899	1,415,367	1,168,664
Operating Expenses			
Electric fuel and purchased power	621,002	416,640	327,464
Gas purchased	486,411	153,027	61,208
Other services' cost of sales	26,069	85,192	55,276
Purchased electric capacity	38,782	28,470	32,126
Employee separation and other merger-related costs	27,418	—	—
Operation and maintenance	264,581	331,770	277,893
Depreciation	131,919	136,340	128,571
Taxes other than income taxes	38,290	37,634	35,737
	1,634,472	1,189,073	918,275
Operating Income	265,427	226,294	250,389
Other Income			
Allowance for equity funds used during construction	2,134	1,337	1,338
Other income	3,321	36,322	14,506
	5,455	37,659	15,844
Interest Expense			
Interest charges	82,527	83,398	74,242
Allowance for borrowed funds used during construction and capitalized interest	(2,019)	(2,996)	(3,926)
	80,508	80,402	70,316
Dividends on Preferred Securities of a Subsidiary Trust	5,688	5,687	1,390
Income Before Income Taxes	184,686	177,864	194,527
Income Taxes	72,276	72,155	78,340
Net Income	112,410	105,709	116,187
Dividends on Preferred Stock	4,352	4,491	8,936
Earnings Applicable to Common Stock	$ 108,058	$ 101,218	$ 107,251

See accompanying Notes to Consolidated Financial Statements.

DELMARVA POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1998	1997	1996
	(Dollars in Thousands)		
Cash Flows From Operating Activities			
Net income	$112,410	$105,709	$116,187
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	141,669	142,734	134,109
Allowance for equity funds used during construction	(2,135)	(1,337)	(1,338)
Investment tax credit adjustments, net	(2,560)	(2,560)	(2,560)
Deferred income taxes, net	5,796	7,169	33,218
Net change in:			
Accounts receivable	(74,321)	(53,911)	(5,030)
Inventories	(6,803)	4,763	(4,489)
Accounts payable	76,910	16,394	18,418
Other current assets & liabilities (1)	38,815	43,450	(48,383)
Gains on sales of assets	(1,549)	(22,896)	(380)
Other, net	(42,027)	(18,250)	(17,100)
Net cash provided by operating activities	246,205	221,265	222,652
Cash Flows From Investing Activities			
Acquisition of businesses, net of cash acquired	(8,970)	(31,994)	(8,301)
Capital expenditures	(114,663)	(156,808)	(165,595)
Investment in partnerships	—	(1,800)	—
Net cash of nonutility subsidiaries transferred to Conectiv	(18,138)	—	—
Sales of nonutility assets	3,805	34,880	793
Deposits to nuclear decommissioning trust funds	(4,238)	(4,240)	(4,238)
Other, net	(360)	3,189	3,478
Net cash used by investing activities	(142,564)	(156,773)	(173,863)
Cash Flows From Financing Activities			
Common dividends paid	(94,700)	(93,811)	(93,290)
Preferred dividends paid	(4,512)	(4,233)	(9,102)
Issuances: Long-term debt	33,000	166,200	—
Common stock	63	17,807	486
Preferred securities (2)	—	—	70,000
Redemptions: Long-term debt	(32,129)	(28,540)	(1,504)
Variable rate demand bonds	—	(1,800)	(1,500)
Common stock	(1,983)	(7,323)	(5,466)
Preferred stock	—	—	(78,383)
Principal portion of capital lease payments	(9,724)	(6,813)	(5,538)
Net change in short-term debt	(26,975)	(102,671)	86,498
Cost of issuances and refinancings	(259)	(4,502)	(3,408)
Net cash used by financing activities	(137,219)	(65,686)	(41,207)
Net change in cash and cash equivalents	(33,578)	(1,194)	7,582
Cash and cash equivalents at beginning of period	35,339	36,533	28,951
Cash and cash equivalents at end of period	$ 1,761	$ 35,339	$ 36,533

(1) Other than debt and deferred income taxes classified as current.

(2) DPL obligated mandatorily redeemable preferred securities of subsidiary trust holding solely DPL debentures.

See accompanying Notes to Consolidated Financial Statements.

DELMARVA POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS

ASSETS	As of December 31, 1998	1997
	(Dollars in Thousands)	
Current Assets		
Cash and cash equivalents	$ 1,761	$ 35,339
Accounts receivable	273,531	197,561
Accounts receivable from associated companies	2,325	—
Inventories, at average costs		
Fuel (coal, oil and gas)	44,212	37,425
Materials and supplies	39,323	40,518
Prepayments	10,735	11,255
Deferred energy costs	—	18,017
Deferred income taxes, net	13,061	776
	384,948	340,891
Investments		
Investment in leveraged leases	—	46,375
Funds held by trustee	60,208	48,086
Other investments	1,103	9,500
	61,311	103,961
Property, Plant and Equipment		
Electric utility plant	3,049,099	3,010,060
Gas utility plant	249,383	241,580
Common utility plant	158,109	154,791
	3,456,591	3,406,431
Less : Accumulated depreciation	1,492,182	1,373,676
Net utility plant in service	1,964,409	2,032,755
Utility construction work-in-progress	138,496	93,017
Leased nuclear fuel, at amortized cost	28,325	31,031
Nonutility property, net	4,560	74,811
Goodwill, net	71,914	92,602
	2,207,704	2,324,216
Deferred Charges and Other Assets		
Prepaid employee benefits costs	94,354	58,111
Unamortized debt expense	12,140	12,911
Deferred debt refinancing costs	16,180	18,760
Deferred recoverable income taxes	82,211	88,683
Other	46,003	67,948
	250,888	246,413
Total Assets	$2,904,851	$3,015,481

See accompanying Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES	As of December 31, 1998	1997
	(Dollars in Thousands)	
Current Liabilities		
Short-term debt	$ 21,700	$ 23,254
Long-term debt due within one year	31,287	33,318
Variable rate demand bonds	71,500	71,500
Accounts payable	177,859	103,607
Taxes accrued	16,257	10,723
Interest accrued	20,604	19,902
Dividends payable	23,615	23,775
Current capital lease obligation	12,481	12,516
Deferred energy costs	413	—
Accrued employee separation and other merger related costs	2,509	—
Other	27,586	35,819
	405,811	334,414
Deferred Credits and Other Liabilities		
Deferred income taxes, net	461,800	492,792
Deferred investment tax credits	37,382	39,942
Long-term capital lease obligation	17,003	19,877
Other	19,747	30,585
	535,932	583,196
Capitalization		
Common stock, $2.25 par value shares authorized : 1998—1,000,000; 1997— 90,000,000 shares outstanding: 1998—1,000; 1997— 61,210,262	2	139,116
Additional paid-in-capital	528,893	526,812
Retained earnings	322,599	300,757
	851,494	966,685
Treasury shares, at cost: 1997—619,237	—	(11,687)
Unearned compensation	—	(502)
Total common stockholder's equity	851,494	954,496
Cumulative preferred stock	89,703	89,703
DPL obligated mandatorily redeemable preferred securities of subsidiary trust holding solely DPL debentures	70,000	70,000
Long-term debt	951,911	983,672
	1,963,108	2,097,871
Commitments and Contingencies (Notes 16 and 19)		
Total Capitalization and Liabilities	$2,904,851	$3,015,481

See accompanying Notes to Consolidated Financial Statements.

DELMARVA POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCKHOLDER'S EQUITY

	Common Shares Outstanding	Par Value	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Unearned Compen-sation	Total
			(Dollars in Thousands)				
Balance as of January 1, 1996	60,759,365	$136,713	$506,328	$281,862	$ (30)	$(1,433)	$923,440
Net income	—	—	—	116,187	—	—	116,187
Cash dividends declared							
Common stock	—	—	—	(93,294)	—	—	(93,294)
Preferred stock	—	—	—	(8,936)	—	—	(8,936)
Issuance of common stock							
Business acquisitions	212,350	—	—	—	4,396	—	4,396
DRIP (1)	21,465	47	388	—	—	—	435
Stock options	2,400	5	45	—	—	—	50
Expenses	—	—	(72)	—	—	—	(72)
Reacquired common stock	(312,861)	—	532	—	(6,504)	363	(5,609)
Amortization of unearned compensation	—	—	687	—	—	(548)	139
Refinancing of preferred stock	—	—	392	(2,215)	—	—	(1,823)
Balance as of December 31, 1996	60,682,719	136,765	508,300	293,604	(2,138)	(1,618)	934,913
Net income	—	—	—	105,709	—	—	105,709
Cash dividends declared							
Common stock	—	—	—	(94,065)	—	—	(94,065)
Preferred stock	—	—	—	(4,491)	—	—	(4,491)
Issuance of common stock							
DRIP (1)	965,655	2,173	15,485	—	—	—	17,658
LTIP (2)	71,103	160	1,200	—	—	(1,360)	—
Stock options	5,450	12	88	—	—	—	100
Other issuance	2,741	6	47	—	—	—	53
Reacquired common stock	(517,406)	—	230	—	(9,549)	2,162	(7,157)
Amortization of unearned compensation	—	—	1,462	—	—	314	1,776
Balance as of December 31, 1997	61,210,262	139,116	526,812	300,757	(11,687)	(502)	954,496
Net income	—	—	—	112,410	—	—	112,410
Cash dividends declared							
Common stock	—	—	—	(94,860)	—	—	(94,860)
Preferred stock	—	—	—	(4,352)	—	—	(4,352)
Issuance of common stock							
Business acquisitions	488,473	—	—	—	9,090	—	9,090
Stock options	3,200	7	56	—	—	—	63
Reacquired common shares	(90,764)	—	50	—	(1,983)	—	(1,933)
LTIP (2)	—	—	—	—	—	(41)	(41)
Transfer of nonutility subsidiaries (3)	—	—	(132,023)	8,644	—	—	(123,379)
Change in shares outstanding due to Merger (4)	(61,831,699)	(139,121)	139,121	—	—	—	—
Transfer of treasury shares to Conectiv due to Merger (5)	221,528	—	(4,580)	—	4,580	—	—
Transfer of unearned compensation to Conectiv due to the Merger (5)	—	—	(543)	—	—	543	—
Balance as of December 31, 1998	1,000	$ 2	$528,893	$322,599	$ —	$ —	$851,494

(1) Dividend Reinvestment and Common Share Purchase Plan (DRIP)—As part of the Merger, DPL's DRIP was transferred to Conectiv.

(2) Long-term incentive plan (LTIP).

(3) On March 1, 1998, DPL's nonutility subsidiaries were transferred to Conectiv.

(4) As part of the Merger, all of DPL's outstanding shares of stock were exchanged for Conectiv shares of stock on a one to one basis. Effective March 1, 1998, DPL had 1,000 shares of stock outstanding, $2.25 par value, held by Conectiv.

(5) DPL's treasury shares and unearned compensation were transferred to Conectiv in conjunction with the Merger.

See accompanying Notes to Consolidated Financial Statements.

DELMARVA POWER & LIGHT COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Nature of Business

Effective March 1, 1998, Delmarva Power & Light Company (DPL) and Atlantic Energy, Inc. (Atlantic) consummated a series of merger transactions (the Merger) by which DPL and Atlantic City Electric Company (ACE) became wholly-owned subsidiaries of Conectiv. As a result of the Merger, Conectiv owns DPL's former nonutility subsidiaries. DPL's former nonutility subsidiaries included Conectiv Services, Inc. (heating, ventilation, and air conditioning construction and services), Conectiv Communications, Inc. (local and long-distance phone service), and Delmarva Capital Investments, Inc. (various nonutility businesses). Refer to Note 4 to the Consolidated Financial Statements for additional information concerning the Merger.

DPL provides regulated electric service (supply and delivery) to approximately 455,300 customers located on the Delmarva Peninsula, which includes Delaware, ten primarily Eastern Shore counties in Maryland, and the Eastern Shore of Virginia, encompassing an area consisting of about 6,000 square miles with a population of approximately 1.2 million. DPL also sells electricity outside its service territory (off-system) and in markets that are not subject to price regulation.

DPL provides regulated gas service (supply and/or transportation) to approximately 105,700 customers located in a service territory that covers about 275 square miles with a population of approximately 485,000 in northern Delaware, including the City of Wilmington. DPL also sells gas off-system and in markets which are not subject to price regulation.

Regulation of Utility Operations

DPL's utility business is subject to regulation with respect to its retail utility sales by the Delaware and Maryland Public Service Commissions (DPSC and MPSC, respectively) and the Virginia State Corporation Commission (VSCC), which have authority over rate matters, accounting, and terms of service. Retail gas sales are subject to regulation by the DPSC. The Federal Energy Regulatory Commission (FERC) also has regulatory authority over certain aspects of DPL's utility business, including the transmission of electricity and gas, the sale of electricity to municipalities and electric cooperatives, and interchange and other purchases and sales of electricity involving other utilities. Excluding off-system sales not subject to price regulation, the percentage of electric and gas utility operating revenues regulated by each regulatory commission for the year ended December 31, 1998, was as follows: DPSC, 67.0%; MPSC, 25.0%; VSCC, 2.3%; and FERC, 5.7%.

DPL is subject to the requirements of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Regulatory commissions occasionally provide for future recovery from customers of current period expenses. When this happens, the expenses are deferred as regulatory assets and subsequently recognized in the Consolidated Statement of Income during the period the expenses are recovered from customers. Similarly, regulatory liabilities may also be created due to the economic impact of an action taken by regulatory commissions.

Refer to Note 10 to the Consolidated Financial Statements for a discussion of regulatory assets arising from the financial effects of rate regulation, and Note 6 to the Consolidated Financial Statements for a discussion of the impact and current status of electric utility industry restructuring.

Financial Statement Presentation

Due to the Merger-related restructuring discussed above, Delmarva Power Financing I (a financing subsidiary) became the only significant remaining wholly-owned subsidiary of DPL as of March 1, 1998. Accordingly, only the January and February 1998 operating results of DPL's former nonutility subsidiaries are included in the 1998 Consolidated Statement of Income. A full year's operating results of DPL's former nonutility subsidiaries are included in the 1997 and 1996 Consolidated Statements of Income.

The consolidated financial statements include the accounts of DPL's wholly-owned subsidiaries. All significant intercompany accounts and transactions are eliminated in consolidation.

Ownership interests of 20% to 50% in other entities are accounted for by the equity method of accounting. Investments in entities accounted for under the equity method are included in "Other investments" on the Consolidated Balance Sheets. Earnings from equity method investees are included in "Other income" in the Consolidated Statements of Income.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and 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 and assumptions.

Revenue Recognition

At the end of each month, there is an amount of electric and gas service rendered from the last meter reading to the month-end which has not yet been billed to customers. The non-energy (base rate) revenues associated with such unbilled services are accrued by DPL.

When interim rates are placed in effect subject to refund, DPL recognizes revenues based on expected final rates.

Revenues from "Other Services" are recognized when services are performed or products are delivered.

Deferred Energy Costs

Energy costs charged to DPL's results of operations generally are adjusted to match energy costs billed to customers (energy revenues) under tariffs for regulated energy sales. The difference between energy revenues and actual energy costs incurred is reported on the Consolidated Balance Sheets as "Deferred energy costs." The deferred balance is subsequently recovered from or returned to utility customers.

Nuclear Fuel

DPL's share of nuclear fuel at the Peach Bottom Atomic Power Station (Peach Bottom) and the Salem Nuclear Generating Station (Salem) is financed through a contract which is accounted for as a capital lease. Nuclear fuel costs, including a provision for the future disposal of spent nuclear fuel, are charged to fuel expense on a unit-of-production basis.

Energy Trading and Risk Management Activities

In December 1998, the Emerging Issues Task Force (EITF), which evaluates accounting issues under the direction of the Financial Accounting Standards Board (FASB), concluded that, effective for financial statements issued for fiscal years beginning after December 15, 1998, contracts entered into in connection with energy trading activities should be marked to market, with gains and losses (unrealized and realized) included in earnings (EITF No. 98-10).

DPL uses futures, options, and swap agreements to hedge firm commitments or anticipated transactions of energy commodities and also creates net open energy commodity positions. DPL used "hedge accounting" as subsequently described, to account for certain energy trading activities during 1996 to 1998. As discussed above, beginning January 1, 1999, EITF No. 98-10 requires mark to market accounting for energy trading contracts, including derivatives. DPL currently uses derivatives mainly in conjunction with energy trading activities.

Under hedge accounting, a derivative, at its inception and on an ongoing basis, is expected to substantially offset adverse price movements in the firm commitment or anticipated transaction that it is hedging. Gains and losses related to qualifying hedges are deferred and are recognized in income when the underlying transaction occurs. If subsequent to being hedged, underlying transactions are no longer likely to occur or the hedge is no longer effective, the related derivatives gains or losses are recognized currently in earnings. Gains and losses on derivatives that do not qualify for hedge accounting are recognized currently in revenues.

Premiums paid for options are included as current assets in the consolidated balance sheet until they are exercised or expire. Margin requirements for futures contracts are also recorded as current assets. Under hedge accounting, unrealized gains and losses on all futures contracts are deferred on the consolidated balance sheet as either current assets or deferred credits. The cash flows from derivatives are included in the cash flows from operations section of the cash flow statement.

In June 1998, the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which becomes effective in the first quarter of fiscal years beginning after June 15, 1999, unless early adoption is elected. SFAS No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires that all derivatives be recognized as assets or liabilities in the balance sheet and be measured at fair value. Under specified conditions, a derivative may be designated as a hedge. The change in the fair value of derivatives, which are not designated as hedges, is recognized in earnings. For derivatives designated as hedges of changes in the fair value of an asset or liability, or as a hedge of exposure to variable cash flows of a forecasted transaction, earnings are affected to the extent the hedge does not match offsetting changes in the hedged item.

DPL currently cannot determine the effect that SFAS No. 133 will have on its financial statements. However, the adoption of EITF 98-10 prior to the implementation of SFAS No. 133 is expected to reduce the impact of SFAS No. 133.

Depreciation Expense

The annual provision for depreciation on utility property is computed on the straight-line basis using composite rates by classes of depreciable property. Accumulated depreciation is charged with the cost of depreciable property retired including removal costs less salvage and other recoveries. The relationship of the annual provision for depreciation for financial accounting purposes to average depreciable property was 3.6% for 1998, 3.7% for 1997, and 3.6% for 1996. Depreciation expense includes a provision for DPL's share of the estimated cost of decommissioning nuclear power plant reactors based on amounts billed to customers for such costs. Refer to Note 8 to the Consolidated Financial Statements for additional information on nuclear decommissioning.

Nonutility property is generally depreciated on a straight-line basis over the useful lives of the assets.

Income Taxes

The consolidated financial statements include two categories of income taxes—current and deferred. Current income taxes represent the amounts of tax expected to be reported on DPL's federal and state income tax returns. Deferred income taxes are discussed below.

Deferred income tax assets and liabilities represent the tax effects of temporary differences between the financial statement and tax bases of existing assets and liabilities and are measured using presently enacted tax rates. The portion of DPL's deferred tax liability applicable to utility operations that has not been recovered from utility customers represents income taxes recoverable in the future and is shown on the Consolidated Balance Sheets as "Deferred recoverable income taxes." Deferred recoverable income taxes were $82.2 million and $88.7 million as of December 31, 1998, and 1997, respectively.

Deferred income tax expense represents the net change during the reporting period in the net deferred tax liability and deferred recoverable income taxes.

Investment tax credits from utility plant purchased in prior years are reported on the Consolidated Balance Sheets as "Deferred investment tax credits." These investment tax credits are being amortized to income over the useful lives of the related utility plant.

Debt Refinancing Costs

Costs of refinancing debt are deferred and amortized over the period during which the refinancing costs are recovered in utility rates.

Interest Expense

The amortization of debt discount, premium, and expense, including refinancing expenses, is included in interest expense.

Utility Plant and Allowance for Funds Used During Construction

Utility plant is stated at original cost, including property additions. Generally, utility plant is subject to a First Mortgage lien. Allowance for Funds Used During Construction (AFUDC) is included in the cost of utility plant and represents the cost of borrowed and equity funds used to finance construction of new utility facilities. In the Consolidated Statements of Income, the borrowed funds component of AFUDC is reported as a reduction of interest expense and the equity funds component of AFUDC is reported as other income. AFUDC was capitalized on utility plant construction at the rates of 8.9% in 1998, 7.5% in 1997, and 6.7% in 1996.

Cash Equivalents

In the consolidated financial statements, DPL considers highly liquid marketable securities and debt instruments purchased with a maturity of three months or less to be cash equivalents.

Funds Held By Trustee

Funds held by trustee are stated at fair market value and primarily include deposits in DPL's external nuclear decommissioning trusts and unexpended, restricted, tax-exempt bond proceeds.

Goodwill

DPL amortizes goodwill arising from business acquisitions over the shorter of the estimated useful life or 40 years.

2. Supplemental Cash Flow Information

In conjunction with the Merger, ownership of DPL's former nonutility subsidiaries was transferred to Conectiv. The assets held by the subsidiaries transferred were primarily leveraged leases, nonutility property, and goodwill. The common stockholder's equity of these nonutility subsidiaries was $123.4 million as of the Merger.

Cash Paid During the Year

	1998	1997	1996
	(Dollars in Thousands)		
Interest, net of capitalized amount	$76,314	$73,211	$67,596
Income taxes, net of refunds	$62,351	$53,550	$56,582

3. Income Taxes

DPL, as a subsidiary of Conectiv, is included in the consolidated federal income tax return of Conectiv. Income taxes are allocated to DPL based upon its taxable income or loss, determined on a separate return basis.

Components of Consolidated Income Tax Expense

		1998	1997	1996
		(Dollars in Thousands)		
Federal:	Current	$57,533	$58,737	$40,953
	Deferred	4,485	6,589	26,131
State:	Current	11,504	8,810	6,729
	Deferred	1,314	579	7,087
Investment tax credit adjustments, net		(2,560)	(2,560)	(2,560)
		$72,276	$72,155	$78,340

Reconciliation of Effective Income Tax Rate

The amount computed by multiplying income before tax by the federal statutory rate is reconciled below to the total income tax expense.

	1998		1997		1996	
	Amount	Rate	Amount	Rate	Amount	Rate
	(Dollars in Thousands)					
Statutory federal income tax expense	$64,640	35%	$62,252	35%	$68,084	35%
Increase due to state income taxes, net of federal tax benefit	8,330	4	6,102	4	8,980	5
Other, net	(694)	—	3,801	2	1,276	—
Total income tax expense	$72,276	39%	$72,155	41%	$78,340	40%

Components of Deferred Income Taxes

The tax effects of temporary differences that give rise to DPL's net deferred tax liability are shown below.

	1998	1997
	(Dollars in Thousands)	
Deferred tax liabilities		
Plant basis differences	$396,543	$409,861
Leveraged leases	—	38,288
Deferred recoverable income taxes	36,504	41,061
Deferred energy costs	(5,459)	7,054
Other	71,756	81,482
Total deferred tax liabilities	499,344	577,746
Deferred tax assets		
Deferred investment tax credits	13,745	14,815
Other	36,860	70,915
Total deferred tax assets	50,605	85,730
Total deferred taxes, net	$448,739	$492,016

Valuation allowances for deferred tax assets were not material as of December 31, 1998 and 1997.

4. Merger with Atlantic

On March 1, 1998, DPL and ACE became wholly-owned subsidiaries of Conectiv. Before the Merger, Atlantic owned ACE, an electric utility serving the southern one-third of New Jersey, and nonutility subsidiaries. As a result of the Merger, Atlantic no longer exists and Conectiv owns, (directly or indirectly), DPL, ACE and nonutility subsidiaries formerly held separately by DPL and Atlantic. Conectiv holds the common stock of DPL and is a registered holding company under the Public Utility Holding Company Act of 1935.

In connection with the Merger, each outstanding share of DPL's common stock, par value $2.25 per share, was exchanged for one share of Conectiv's common stock, par value $0.01 per share. Also, DPL's Board of Directors declared that a dividend consisting of the common stock of its nonutility subsidiaries be paid to Conectiv. These nonutility subsidiaries had common stockholder's equity of $123.4 million as of February 28, 1998 and net losses of $3.5 million for January 1 to February 28, 1998.

DPL recorded a $27.4 million charge ($16.6 million after taxes) in 1998 for costs of employee separation programs utilized to reduce the workforce by 421 employees and other Merger-related costs. The charge to expense was reduced by a net $45.5 million gain from curtailment and settlements of pension and postretirement health care benefits. Of the $27.4 million of costs discussed above, $21.2 million had been paid as of December 31, 1998, $3.7 million will not require the use of operating funds, and $2.5 million remains to be paid from operating funds.

5. Sale of Pine Grove Landfill and Waste Hauling Companies

In the fourth quarter 1997, a subsidiary of DPL sold the Pine Grove Landfill and its related waste-hauling company. The subsidiaries which were sold had a net book value of approximately $11.3 million and reported revenues in 1997 of approximately $12.7 million. Pre-tax proceeds received from the sale were $34.2 million ($33.4 million net of cash sold), resulting in a pre-tax gain of $22.9 million ($13.7 million after income taxes).

6. Rate Matters

Merger Rate Decrease

DPL is sharing a portion of the net cost savings expected to result from the Merger with its customers through reduced electric and gas retail customer base rates. DPL's total Merger-related base rate decrease of $13.0 million is being phased-in as follows: (1) $11.5 million effective March 1, 1998, (2) $1.1 million effective March 1, 1999, and (3) $0.4 million effective March 1, 2000.

Electric Utility Industry Restructuring

As discussed below, restructuring of the electric utility industry is underway in Delaware, Maryland, and Virginia. Generally with restructuring, the supply component of the price charged to a customer for electricity will be deregulated, and electric suppliers would compete to supply electricity to customers. Customers will continue to pay the local utility a regulated price for the delivery of the electricity over the transmission and distribution system.

Stranded costs are costs which may not be recoverable in a competitive energy supply market due to lower prices or customers choosing a different supplier. Stranded costs generally include above-market costs associated with generation facilities or long-term purchased power agreements, and regulatory assets.

When a specific plan that deregulates electricity supply becomes final, DPL would cease applying SFAS No. 71 to its electricity supply business in the regulatory jurisdiction to which the plan applies. To the extent that a deregulation transition plan provides for recovery of stranded costs through cash flows from the regulated transmission and distribution business, the stranded costs would continue to be recognized as assets under SFAS No. 71. Any stranded costs (including regulatory assets) for which cost recovery is not provided would be expensed.

The amount of stranded costs ultimately recovered from utility customers, if any, and the full impact of legislation deregulating the electric utility industry in Delaware, Maryland and Virginia cannot be predicted. Also, the quantification of stranded costs under existing generally accepted accounting principles (GAAP) differs from methods used in regulatory filings. Among other differences, GAAP precludes recognition of the gains on plants (or purchased power contracts) not impaired, but requires write down of the plants that are impaired. Due to these considerations, market conditions, timing and other factors, DPL currently cannot predict the ultimate effects that electric utility industry deregulation may have on its financial statements, although deregulation may have a material adverse effect on DPL's results of operations.

Delaware

The Alliance for Fair Electric Competition Today, which includes DPL, worked with Delaware executive branch representatives and representatives of DPSC Staff to develop consensus restructuring legislation. House Bill No. 10, with several amendments, passed the Delaware House of Representatives, and the Delaware Senate. The Governor of Delaware is expected to sign the legislation.

House Bill No. 10 would allow DPL's Delaware customers to choose their electricity suppliers beginning on October 1, 1999 (for customers with peak demands of 1,000 kilowatts or more), January 15, 2000 (for customers with peak demands of 300 kilowatts or more), and 18 months after the legislation is enacted (for all other customers). House Bill No. 10 also provides for a residential rate reduction of 7.5% beginning October 1, 1999. Thereafter, except for a deferred fuel balance "true-up" and increases for extraordinary costs, residential rates may not be changed for four years; rates for customers in commercial and industrial rate classes may not be changed for three years. Under House Bill No. 10, certain low-income energy assistance and environmental programs are funded at an annual level of about $1.6 million by a charge in electric rates.

Among other matters, unbundled rates to be charged by DPL during these "rate freeze" periods have been agreed upon by a number of participants in the restructuring plan proceeding contemplated by House Bill No. 10. Included within the agreement on unbundled rates, DPL would recover $16 million (Delaware retail basis) of stranded costs, and electric rates would not be changed in the event DPL sells or transfers generating assets.

Maryland

In 1997, the MPSC issued two orders which provide for retail electric competition to begin July 3, 2000, and be phased-in over a three-year period (one-third of the customers per year). Enabling legislation and resolution of complex issues such as stranded costs and utility taxation will be necessary for implementation of retail competition in Maryland.

On July 1, 1998, DPL filed with the MPSC its quantification of stranded costs and computation of unbundled rates, which are being considered in Case No. 8795. The MPSC is expected to issue its order on DPL's stranded cost recovery and unbundled rates by October 1, 1999. DPL estimated stranded costs to be $217 million on a DPL system-wide basis ($69 million Maryland retail portion), including $123 million attributable to generating units, $54 million associated with purchased power contracts, $21 million related to fuel inventory financing costs, and $19 million of regulatory assets. DPL proposed full recovery of the Maryland portion of the stranded costs over a three-year period, starting with the commencement of retail competition on July 3, 2000.

The MPSC Staff and other parties contend that the market value of DPL's generating assets exceeds their book value and thus that DPL has negative stranded costs, or so-called "stranded benefits." Proposals for rate reductions based on a sharing of these alleged benefits and other factors have been submitted to the MPSC in Case No. 8795. The proposed rate reductions vary widely, from 3% up to levels which, if adopted, would have a material adverse impact on DPL's results of operations.

Maryland's electric utilities, including DPL, continue to meet with the MPSC Staff and others to develop consensus enabling restructuring and related tax legislation for possible passage in the 1999 legislative session.

Virginia

Comprehensive electric utility restructuring legislation has been introduced in the Virginia General Assembly. Senate Bill No. 1269 and identical House Bill No. 2615, introduced on January 21, 1999, were drafted by a joint House-Senate study committee created in 1996 to consider restructuring issues. Significant provisions of these Bills provide for:

- Phase-in of retail electric competition beginning January 1, 2002
- Rates in effect on January 1, 2001 to become "capped rates" to continue in effect through July 1, 2007, except for adjustments for changes in fuel costs and state tax rates
- Customers choosing an electricity supplier other than their incumbent utility continue to pay capped transmission and distribution rates but, instead of the capped generation rate, they would pay a "wires" charge which would be the difference between the capped generation rate and projected market prices for electricity
- Just and reasonable net stranded costs are to be recovered through capped rates and wires charges during the period January 1, 2001 through July 1, 2007

7. Energy Hedging and Trading Activities

DPL actively participates in the wholesale energy markets to support its wholesale utility and competitive retail marketing activities. DPL engages in commodity hedging activities to minimize the risk of market fluctuations associated with the purchase and sale of energy commodities (natural gas and electricity). Some

hedging activities are conducted using energy derivatives. The remainder of DPL's hedging activity is conducted by backing physical transactions with offsetting physical positions. The hedging objectives include the assurance of stable and known minimum cash flows and the fixing of favorable prices and margins when they become available. DPL also engages in energy commodity trading and arbitrage activities, which expose DPL to commodity market risk when, at times, DPL creates net open energy commodity positions or allows net open positions to continue. To the extent that DPL has net open positions, controls are in place that are intended to keep risk exposures within management-approved risk tolerance levels.

DPL utilizes futures, options, and swap agreements to manage risk. Futures help manage commodity price risk by fixing purchase or sales prices. Options provide a floor or ceiling on future purchases or sales prices while allowing DPL to benefit from favorable price movements. Swaps are structured to provide the same risk protection as futures and options. Basis swaps are used to manage risk by fixing the basis differential that exists between a delivery location index and the commodity futures price.

Exposed commodity positions may be "long" or "short." A long position indicates that DPL has an excess of the commodity available for sale. A short position means DPL will have to obtain additional commodity to fulfill its sales requirements. A "delta" position is the conversion of an option into futures contract equivalents. The option delta is dependent upon the strike price, volatility, current market price and time-value of the option.

Natural Gas Activities

At December 31, 1998, there were 1,314 (2,697 long, 1,383 short) net open futures contracts, representing a notional quantity of 13.1 billion cubic feet (Bcf) through February of 2001. In addition, DPL had a net long commodity swap position equivalent to 459 futures contracts (4.6 Bcf) and a net long basis swap position equivalent to 531 futures contracts (5.3 Bcf).

DPL entered into 1,474 of the net long open futures contracts in order to hedge the gas marketing activities of various business units. Other gas commodity hedges at December 31, 1998 included a net long commodity swap position equivalent to 262 futures contracts and a net long basis swap position equivalent to 471 futures contracts. During the year ended December 31, 1998, $4.0 million of losses were recognized on the settlement of natural gas futures, swaps and options hedging contracts for the unregulated business units. These losses were offset by gains on the physical commodity transactions being hedged. A total of $8.6 million of unrealized losses were deferred in the Consolidated Balance Sheet as of December 31, 1998. These losses are offset by gains on the physical commodity being hedged.

During the year ended December 31, 1998, a trading gain of $0.2 million was realized on natural gas financial derivative activities that were not classified as hedges. Unrealized gains in forward gas trading positions (physical and financial) totaled $0.8 million at December 31, 1998.

The annual average unrealized loss on trading activities, based on month-end averages, was $0.1 million.

At December 31, 1997, there were 220 open futures contracts and 30 open options contracts to purchase natural gas, representing a notional quantity of 2.5 Bcf through October of 1999 and 60 open options contracts, to sell natural gas, representing a notional quantity of 0.6 Bcf through July of 1998. A total of $0.5 million of unrealized losses were deferred in the Consolidated Balance Sheet as of December 31, 1997.

Electricity Activities

At December 31, 1998, DPL had a total short exposure of 102,400 megawatt-hours (MWH) (84,700 on peak, 17,700 off-peak) through December 1999. The overall position included a long option delta exposure of 2,300 MWH. The remaining exposure was comprised of forward contracts.

During the year ended December 31, 1998, a net-gain of $0.1 million was recognized on the settlement of electric hedging options and swaps. This gain was offset by losses on the physical commodity transactions being hedged. A total of $0.3 million of unrealized losses were deferred in the Consolidated Balance Sheet as of December 31, 1998. During the year ended December 31, 1998 realized gains of $10.2 million were recorded on power trading activities (physical and financial) not classified as hedges. At December 31, 1998 unrealized gains on power trading activities amounted to $1.2 million. The annual average unrealized gain on trading activities, based on month-end averages, was $1.3 million.

At December 31, 1997, there was one swap contract to sell electricity, representing a notional quantity of 68,000 MWH, through August of 1998. A total of $0.2 million of unrealized losses were deferred on the Consolidated Balance Sheet as of December 31, 1997.

Credit Exposure

Counterparties to its various hedging and trading contracts expose DPL to credit losses in the event of nonperformance. Management has evaluated such risk and implemented credit checks and has established reserves for credit losses. A large portion of the hedging and trading activities are conducted on national exchanges backed by exchange clearinghouses. Management believes that the overall business risk is minimized as a result of these procedures.

8. Nuclear Decommissioning

DPL records a liability for its share of the estimated cost of decommissioning the Peach Bottom and Salem nuclear reactors over the remaining lives of the plants based on amounts collected in rates charged to electric customers. For utility rate-setting purposes, DPL estimates its share of future nuclear decommissioning costs ($157 million) based on Nuclear Regulatory Commission (NRC) regulations concerning the minimum financial assurance amount for nuclear decommissioning.

DPL's accrued nuclear decommissioning liability, which is reflected in the accumulated reserve for depreciation, was $69.5 million as of December 31, 1998. The provision reflected in depreciation expense for nuclear decommissioning was $4.2 million in 1998, $4.2 million in 1997, and $4.2 million in 1996. External trust funds established by DPL for the purpose of funding nuclear decommissioning costs had an aggregate book balance (stated at fair market value) of $57.7 million as of December 31, 1998.

Earnings on the trust funds are recorded as an increase to the accrued nuclear decommissioning liability, which, in effect, reduces the expense recorded for nuclear decommissioning.

The ultimate cost of nuclear decommissioning for the Peach Bottom and Salem reactors may exceed the current estimates which are updated periodically.

The staff of the Securities and Exchange Commission has questioned certain of the current accounting practices of the electric utility industry, including DPL, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In February 1996, the FASB issued the Exposure Draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets," which proposed changes in the accounting for closure and removal costs of long-lived assets, including the recognition, measurement, and classification of decommissioning costs for nuclear generating stations. If the proposed changes were adopted: (1) annual provisions for decommissioning would increase, (2) the estimated cost for decommissioning would be recorded as a liability rather than as accumulated depreciation, and (3) trust fund income from the external decommissioning trusts would be reported as investment income rather than as a reduction of decommissioning expense. The FASB is expected to issue a revised Exposure Draft in the second quarter of 1999.

9. Jointly Owned Plant

DPL's Consolidated Balance Sheets include its proportionate share of assets and liabilities related to jointly owned plant. DPL's share of operating and maintenance expenses of the jointly owned plant is included in the corresponding expenses in the Consolidated Statements of Income. DPL is responsible for providing its share of financing for the jointly-owned facilities.

Information with respect to DPL's share of jointly owned plant as of December 31, 1998 was as follows:

	Ownership Share	Megawatt Capability Owned	Plant in Service	Accumulated Depreciation	Construction Work in Progress
			(Dollars in Thousands)		
Nuclear					
Peach Bottom	7.51%	164 MW	$136,044	$ 63,040*	$13,950
Salem	7.41%	164 MW	247,095	89,025*	5,050
Coal-Fired					
Keystone	3.70%	63 MW	20,781	9,245	18
Conemaugh	3.72%	63 MW	33,207	11,710	245
Transmission Facilities	Various		4,567	2,407	—
Other Facilities	Various		2,159	295	4,340
Total			$443,853	$175,722	$23,603

* Excludes nuclear decommissioning reserve.

10. Regulatory Assets

In conformity with generally accepted accounting principles, DPL's accounting policies reflect the financial effects of rate regulation and decisions issued by regulatory commissions having jurisdiction over DPL's utility business. In accordance with the provisions of SFAS No. 71, DPL defers expense recognition of certain costs and records an asset, a result of the effects of rate regulation. Except for deferred energy costs, which are classified as a current asset or liability, these "regulatory assets" are included on DPL's Consolidated Balance Sheets under "Deferred Charges and Other Assets." The costs of these assets are either being recovered or are probable of being recovered through customer rates. Generally, the costs of these assets are recognized in operating expenses over the period the cost is recovered from customers. See Note 6 to the Consolidated Financial Statements for information about the impact of electric utility restructuring on the accounting for regulatory assets.

DPL's regulatory assets and liabilities as of December 31, 1998 and 1997 are shown in the following table:

	1998	1997
	(Dollars in millions)	
Deferred energy costs	$ (0.4)	$ 18.0
Deferred debt refinancing costs	16.2	18.8
Deferred recoverable income taxes	82.2	88.7
Deferred recoverable plant costs	7.6	7.8
Deferred costs for nuclear decontamination/decommissioning	5.7	6.3
Deferred demand-side management costs	5.6	6.2
Other	2.2	1.9
Total	$119.1	$147.7

Deferred Energy Costs: Represents the difference between fuel revenues and actual fuel costs incurred. The deferred balance is generally recovered from or returned to utility customers within one year.

Deferred Debt Refinancing Costs: Represents the costs of refinancing debt of the utility business which are deferred and amortized over the period recovered in customer rates, which is generally the life of the new debt.

Deferred Recoverable Income Taxes: Represents the portion of DPL's deferred tax liability applicable to utility operations that has not been recovered from utility customers and is recoverable in the future. As temporary differences between the financial statement and tax bases of assets reverse, deferred recoverable income taxes are amortized.

Deferred Recoverable Plant Costs: Represents utility plant construction costs excluded from plant in-service which are being recovered over 21 remaining years.

Deferred Costs for Nuclear Decontamination/Decommissioning: Represents amounts being recovered through fuel adjustment clause revenues for DPL's liability under the Energy Policy Act of 1992 for clean-up of gaseous diffusion enrichment facilities of the U.S. government.

Deferred Demand-Side Management Costs: Represents deferred costs of programs that allow DPL to reduce the peak demand for power. These costs are being recovered over 5 years.

11. Common Stock

The public holders of DPL's common stock prior to the Merger exchanged each share of DPL's common stock for one share of Conectiv common stock. Effective with the Merger, Conectiv owns all 1,000 outstanding shares of DPL's common stock ($2.25 par value per share). See Note 4 to the Consolidated Financial Statements for additional information concerning the Merger. Also see the Statement of Changes in Common Stockholder's Equity for information about changes in common stock during 1998, 1997, and 1996.

DPL's certificate of incorporation requires payment of all preferred dividends in arrears (if any) prior to payment of common dividends to Conectiv.

12. Cumulative Preferred Stock

DPL has $1, $25 and $100 par value per share preferred stock for which 10,000,000, 3,000,000 and 1,800,000 shares are authorized, respectively. No shares of the $1 par value per share preferred stock are outstanding. Shares outstanding for each series of the $25 and $100 par value per share preferred stock are listed below. Redemptions of preferred stock in 1996 are discussed in Note 13 to the Consolidated Financial Statements.

Series	Current Redemption Price	Shares Outstanding 1998	Shares Outstanding 1997	Amount 1998	Amount 1997
				(Dollars in Thousands)	
$25 per share par value 7¾%	(1)	316,500	316,500	$ 7,913	$ 7,913
$100 per share par value					
3.70%-5%	$103-$105	181,698	181,698	18,170	18,170
6¾%	(2)	35,000	35,000	3,500	3,500
Adjustable rate(3)	$100	151,200	151,200	15,120	15,120
Auction rate(4)	$100	450,000	450,000	45,000	45,000
				$89,703	$89,703

(1) Redeemable beginning September 30, 2002, at $25 per share.
(2) Redeemable beginning November 1, 2003, at $100 per share.
(3) Average dividend rates were 5.5 % during 1998 and 1997.
(4) Average dividend rates were 4.2 % during 1998 and 1997.

13. DPL Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely DPL Debentures

A wholly owned subsidiary trust (Delmarva Power Financing I) was established in 1996 as a financing subsidiary of DPL for the purposes of issuing common and preferred trust securities and holding 8.125% Junior Subordinated Debentures (the Debentures). The Debentures held by the trust are its only assets. The trust uses interest payments received on the Debentures it holds to make cash distributions on the trust securities. The combination of the obligations of DPL pursuant to the Debentures, and DPL's guarantee of distributions with respect to trust securities, to the extent the trust has funds available therefor, constitute a full and unconditional guarantee by DPL of the obligations of the trust under the trust securities the trust has issued. DPL is the owner of all of the common securities of the trust, which constitute approximately 3% of the liquidation amount of all of the trust securities issued by the trust.

In October 1996, the trust issued $70 million in aggregate liquidation amount of 8.125% Cumulative Trust Preferred Capital Securities (representing 2,800,000 preferred securities at $25 per security). At the same time, $72.165 million in aggregate principal amount of 8.125% Junior Subordinated Debentures, Series I, due 2036 were issued to the trust. For consolidated financial reporting purposes, the Debentures are eliminated in consolidation against the trust's investment in the Debentures. The preferred trust securities are subject to mandatory redemption upon payment of the Debentures at maturity or upon redemption. The Debentures are subject to redemption, in whole or in part at the option of DPL, at 100% of their principal amount plus accrued interest, after an initial period during which they may not be redeemed and at any time upon the occurrence of certain events.

In October 1996, DPL used part of the proceeds received from the trust to purchase and retire $32.1 million of its $25 par value, 7.75% series preferred stock, and $31.3 million of various series of its $100 par value preferred stock which had an average dividend rate of 5.68%. In December 1996, DPL redeemed its entire 7.52% preferred stock series which had a total par value of $15.0 million.

14. Debt

Substantially all utility plant of DPL is subject to the lien of the Mortgage and Deed of Trust collateralizing DPL's First Mortgage Bonds.

DPL funds its interim financing requirements by issuing commercial paper and borrowing against bank credit lines (at December 31, 1998, total borrowing capacity under these facilities was $225 million, and $203.3 million was available for borrowing). The weighted average interest rates on short-term debt outstanding as of December 31, 1998 and 1997 were 5.2% and 6.6%, respectively.

Maturities of long-term debt and sinking fund requirements during the next five years are as follows: 1999—$31.3 million; 2000—$1.5 million; 2001—$2.3 million; 2002—$48.1 million; 2003—$92.3 million.

In December 1998, DPL redeemed $6.0 million of 5.75% Pollution Control Bonds at maturity.

In June 1998, DPL repaid at maturity $25.0 million of 5.69% Medium-Term Notes and $1.0 million of 6.95% Amortizing First Mortgage Bonds.

In January 1998, DPL issued $33.0 million of 6.81% unsecured Medium-Term Notes which mature in 20 years. DPL used $25.4 million of the proceeds to refinance short-term debt. In recognition of this refinancing $25.4 million of short-term debt was reclassified to long-term debt on the Consolidated Balance Sheet as of December 31, 1997.

In the fourth quarter of 1997, DPL issued $42.0 million of unsecured Medium-Term Notes with maturities of 5 to 9 years and interest rates of 6.6% to 6.8%. The proceeds were used to refinance short-term debt.

In September 1997, DPL redeemed $25.0 million of 6⅜% First Mortgage Bonds at maturity through the issuance of short-term debt.

In February 1997, DPL issued $124.2 million of unsecured Medium-Term Notes with maturities of 10 to 30 years and interest rates of 7.06% to 7.72%. The proceeds were used to refinance short-term debt.

Long-term debt outstanding as of December 31, 1998 and 1997 is presented below:

	Interest Rates	Due	1998	1997
			(Dollars in Thousands)	
First Mortgage Bonds	6.95%	2002	$ 30,000	$ 30,000
	6.40%	2003	90,000	90,000
	7.15%-8.15%	2011-2015	115,500	115,500
	5.90%-7.60%	2017-2021	163,200	163,200
	6.85%-8.50%	2022-2025	165,000	165,000
	6.05%	2032	15,000	15,000
Amortizing First Mortgage Bonds	6.95%	1998-2008	24,149	25,103
Total First Mortgage Bonds			602,849	603,803
Pollution Control Notes:				
Series 1973	5.75%	1998	—	6,000
Series 1976	7.125%-7.25%	1999-2006	2,800	2,900
Medium-Term Notes:	5.69%	1998	—	25,000
	7.50%	1999	30,000	30,000
	6.59%-9.29%	2002	16,000	16,000
	8.30%	2004	35,000	35,000
	6.94%	2005	10,000	10,000
	6.84%	2006	20,000	20,000
	7.06%-8.125%	2007	91,500	91,500
	7.54%-7.62%	2017	40,700	40,700
	6.81%	2018	33,000	25,430
	7.61%-9.95%	2019-2021	73,000	73,000
	7.72%	2027	30,000	30,000
Other Obligations:	6.00%-9.50%	(1)	—	232
	8.00%	(1)	—	3,660
	9.65%	(1)	—	5,354
Unamortized premium and discount, net			(1,651)	(1,589)
Current maturities of long-term debt			(31,287)	(33,318)
Total long-term debt			951,911	983,672
Variable Rate Demand Bonds (2)			71,500	71,500
Total long-term debt and Variable Rate Demand Bonds			$1,023,411	$1,055,172

(1) Debt of former subsidiaries which was transferred to Conectiv in the Merger.

(2) DPL's debt obligations included Variable Rate Demand Bonds (VRDB) in the amount of $71.5 million as of December 31, 1998 and 1997. The VRDB are classified as current liabilities because the VRDB are due on demand by the bondholder. However, bonds submitted to DPL for purchase are remarketed by a remarketing agent on a best efforts basis. DPL expects that bonds submitted for purchase will continue to be remarketed successfully due to DPL's credit worthiness and the bonds' interest rates being set at market. DPL also may utilize one of the fixed rate/fixed term conversion options of the bonds. Thus, DPL considers the VRDB to be a source of long-term financing. The $71.5 million balance of VRDB outstanding as of December 31, 1998, matures in 2017 ($26.0 million), 2028 ($15.5 million), and 2029 ($30.0 million). Average annual interest rates on the VRDB were 3.5% in 1998 and 3.8% in 1997.

15. Fair Value of Financial Instruments

The year-end fair values of certain financial instruments are listed below. The fair values were based on quoted market prices of DPL's securities or securities with similar characteristics.

	1998		1997	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Dollars in Thousands)			
Funds held by trustee	$ 60,208	$ 60,208	$ 48,086	$ 48,086
DBL Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely DPL Debentures	$ 70,000	$ 71,764	$ 70,000	$ 72,464
Long-Term Debt	$951,911	$1,041,895	$983,672	$1,053,810

16. Commitments

DPL's expected capital and acquisition expenditures are estimated to be approximately $138 million in 1999.

As of December 31, 1998, DPL's commitments under long-term purchased power contracts included 237 megawatts (MW) of capacity and 100 MW of energy. Historical information is presented below for these contracts and a 48 MW capacity contract which was suspended in October 1996.

	1998	1997	1996
Percent of system capacity	6.7%	6.4%	6.4%
Percent of energy output	18.5%	12.1%	10.6%
Capacity charges ($ in millions)	$38.8	$28.5	$32.1
Energy charges ($ in millions)	$57.7	$38.1	$32.5

Based on existing contacts as of December 31, 1998, DPL's future commitments for capacity and energy under long-term purchased power contracts are estimated to be $84.2 million in 1999; $91.1 million in 2000; $94.1 million in 2001; $97.7 million in 2002, and $99.3 million in 2003. Due to the uncertainties surrounding restructuring of the electric utility industry, DPL has not forecasted its long-term purchased power commitments beyond 2003.

DPL's share of nuclear fuel at Peach Bottom and Salem is financed through a nuclear fuel energy contract, which is accounted for as a capital lease. Payments under the contract are based on the quantity of nuclear fuel burned by the plants. DPL's obligation under the contract is generally the net book value of the nuclear fuel financed, which was $28.3 million as of December 31, 1998.

DPL leases an 11.9% interest in the Merrill Creek Reservoir. The lease is considered an operating lease and payments over the remaining lease term, which ends in 2032, are $150.5 million in aggregate. DPL also has long-term leases for certain other facilities and equipment. Minimum commitments as of December 31, 1998 under the Merrill Creek Reservoir lease and all other noncancelable lease agreements (excluding payments under the nuclear fuel energy contract which cannot be reasonably estimated) are as follows: 1999—$6.2 million; 2000—$5.1 million; 2001—$5.2 million; 2002—$4.5 million; 2003—$6.5 million; after 2003—$131.2 million; total—$158.7 million. Approximately 95% of the minimum lease commitments shown above are payments due under the Merrill Creek Reservoir lease.

Rentals Charged To Operating Expenses

The following amounts were charged to operating expenses for rental payments under both capital and operating leases.

	1998	1997	1996
	(Dollars in Thousands)		
Interest on capital leases	$ 1,467	$ 1,548	$ 1,628
Amortization of capital leases	9,838	6,499	5,653
Operating leases	13,190	11,590	13,795
	$24,495	$19,637	$21,076

17. Pension and Other Postretirement Benefits

	1998	1997	1996
Assumptions			
Discount rates used to determine projected benefit obligation as of December 31	6.75%	7.00%	7.50%
Expected long-term rates of return on assets	9.00%	9.00%	9.00%
Rates of increase in compensation levels	4.50%	5.00%	5.00%
Health care cost trend rate on covered charges	7.00%	7.50%	8.00%

The health-care cost trend rate, or the expected rate of increase in health-care costs, is assumed to gradually decrease to 5.0% by 2002. Increasing the health-care cost trend rates of future years by one percentage point would increase the accumulated postretirement benefit obligation by $8.5 million and would increase annual aggregate service and interest costs by $0.5 million. Decreasing the health-care cost trend rates of future years by one percentage point would decrease the accumulated postretirement benefit obligation by $7.5 million and would decrease annual aggregate service and interest costs by $0.5 million.

The following schedules reconcile the beginning and ending balances of the pension and other postretirement benefit obligations and related plan assets. Other postretirement benefits include medical benefits for retirees and their spouses and retiree life insurance.

Change in Benefit Obligation

	Pension Benefits		Other Postretirement Benefits	
	1998	1997	1998	1997
	(Dollars in Thousands)			
Benefit obligation at beginning of year	$ 515,590	$450,640	$80,500	$73,841
Service cost	12,635	12,779	2,185	2,393
Interest cost	31,138	34,173	6,289	5,547
Plan participants' contributions	—	—	497	304
Plan amendments	(10,770)	—	—	—
Actuarial (gain) loss	45,884	40,492	3,960	4,781
Special termination benefits	47,764	—	1,412	—
Curtailment (gain) loss	(6,373)	—	17	—
Settlement (gain) loss	(45,609)	—	6,457	—
Benefits paid	(142,510)	(22,494)	(4,278)	(6,366)
Benefit obligation at end of year	$ 447,749	$515,590	$97,039	$80,500

Change in Plan Assets

	Pension Benefits		Other Postretirement Benefits	
	1998	1997	1998	1997
	(Dollars in Thousands)			
Fair value of assets at beginning of year	$ 771,257	$676,189	$48,591	$36,075
Actual return on plan assets	107,887	117,562	5,551	9,984
Employer contributions	—	—	14,598	8,594
Plan participant contributions	—	—	497	304
Benefits paid	(142,510)	(22,494)	(4,278)	(6,366)
Fair value of assets at end of year	$ 736,634	$771,257	$64,959	$48,591

Reconciliation of Funded Status of the Plans

	Pension Benefits		Other Postretirement Benefits	
	1998	1997	1998	1997
	(Dollars in Thousands)			
Funded status at end of year	$ 288,885	$ 255,667	$(32,080)	$(31,909)
Unrecognized net actuarial gain	(196,927)	(205,732)	(5,992)	(18,238)
Unrecognized prior service cost	12,204	26,945	248	317
Unrecognized net transition (asset) obligation	(15,773)	(23,199)	43,787	54,259
Net amount recognized at end of year	$ 88,389	$ 53,681	$ 5,963	$ 4,429

Based on fair values as of December 31, 1998, the pension plan assets were comprised of publicly traded equity securities ($493.5 million or 67%) and fixed income obligations ($243.1 million or 33%). Based on fair values as of December 31, 1998, the other postretirement benefit plan assets included equity securities ($43.4 million or 67%) and fixed income obligations ($21.6 million or 33%).

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	1998	1997	1996	1998	1997	1996
	(Dollars in Thousands)					
Service cost	$ 12,635	$ 12,779	$ 13,172	$ 2,185	$ 2,393	$ 2,512
Interest cost	31,138	34,173	32,531	6,289	5,547	5,213
Expected return on assets	(64,247)	(60,020)	(54,485)	(4,000)	(2,580)	(1,722)
Amortization of:						
Transition obligation (asset)	(2,764)	(3,314)	(3,314)	3,244	3,617	3,617
Prior service cost	1,911	2,035	2,048	50	53	53
Actuarial gain	(9,163)	(7,814)	(4,573)	(566)	(712)	(500)
Cost before items below	$(30,490)	$(22,161)	$(14,621)	$ 7,202	$ 8,318	$ 9,173
Special termination benefits	47,764	—	—	1,412	—	—
Curtailment (gain) loss	(6,373)	—	—	17	—	—
Settlement (gain) loss	(45,609)	—	—	6,457	—	—
Total net periodic benefit cost	$(34,708)	$(22,161)	$(14,621)	$15,088	$ 8,318	$ 9,173
Portion of net periodic benefit cost included in results of operations	$(26,996)	$(16,621)	$(10,966)	$14,368	$ 6,239	$ 6,880

The special termination benefits and curtailment and settlement gains and losses shown in the preceeding table for 1998 resulted from Merger-related employee separation programs discussed in Note 4 to the Consolidated Financial Statements.

Effective January 1, 1999, DPL's covered employees began participating in a "cash balance" pension plan adopted by Conectiv. Contributions, which vary based on the employee's age and years of service, are made to individual employee accounts provided for under the plan. The "cash balance" of each employee's account increases based on employer contributions and interest income credited to the accounts. The aggregate of the employee's accounts will be DPL's pension obligation.

Conectiv maintains 401(k) savings plans for covered employees. Prior to the Merger, DPL provided 401(k) plans with benefit levels similar to the Conectiv 401(k) plans. Conectiv contributes to the plans, in the form of Conectiv stock, at varying levels up to $0.50 for each dollar contributed by covered employees, for up to 6% of employee base pay. The amount expensed for Conectiv's matching contributions was $2.7 million in 1998, $3.0 million in 1997, and $2.4 million in 1996.

18. Salem Nuclear Generating Station

DPL owns 7.41% of Salem, which consists of two pressurized water nuclear reactors operated by Public Service Electric & Gas Company (PSE&G). Salem Units 1 and 2 were removed from operation by PSE&G in the second quarter of 1995 due to operational problems, and maintenance and safety concerns. After receiving NRC authorization, PSE&G returned Unit 2 to service on August 30, 1997, and returned Unit 1 to service on April 17, 1998. The net increase in fuel expenses due to unrecovered replacement power and other costs, net of the benefit of lawsuit settlement proceeds received in 1997 was $2.4 million in 1998, $3.1 million in 1997, and $10.1 million in 1996. The outages also caused increases in operation and maintenance costs of approximately $4 million in 1997 and $9 million in 1996.

As previously reported, on February 27, 1996, the co-owners of Salem, including DPL, filed a complaint in the United States District Court for New Jersey against Westinghouse Electric Corporation (Westinghouse), the designer and manufacturer of the Salem steam generators. The complaint, which sought to recover from Westinghouse the costs associated with and resulting from the cracks discovered in Salem's steam generators and with replacing such steam generators, alleges violations of federal and New Jersey Racketeer Influenced and Corrupt Organizations Acts, fraud, negligent misrepresentation and breach of contract. On November 4, 1998, the Court granted Westinghouse's motion for summary judgement with regard to the federal Racketeer Influenced and Corrupt Organizations Act claim, and dismissed the remaining state law claims without prejudice. On November 18, 1998, the co-owners re-filed their state law claims against Westinghouse in the Superior Court of New Jersey. The co-owners also filed an appeal of the District Court's dismissal with the United States Court of Appeals for the Third Circuit.

19. Contingencies

Environmental Matters

DPL is subject to regulation with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal, and limitation on land use by various federal, regional, state, and local authorities. Costs may be incurred to clean up facilities found to be contaminated due to past disposal practices. Federal and state statutes authorize governmental agencies to compel responsible parties to clean up certain abandoned or uncontrolled hazardous waste sites. DPL is currently a potentially responsible party at three federal superfund sites and is alleged to be a third-party contributor at three other federal superfund sites. DPL also has two former coal gasification sites in Delaware and one former coal gasification site in Maryland, each of which is a state superfund site. In addition, on August 11, 1998, the Delaware Department of Natural Resources and Environmental Control notified DPL that it is a potentially responsible party liable for clean-up of the Wilmington Public Works Yard as a former owner of the property. There is $2 million included

in DPL's current liabilities as of December 31, 1998 and 1997, for clean-up and other potential costs related to these sites. DPL does not expect such future costs to have a material effect on the financial position or results of their operations.

Nuclear Insurance

In conjunction with DPL's ownership interests in Peach Bottom and Salem, DPL could be assessed for a portion of any third-party claims associated with an incident at any commercial nuclear power plant in the United States. Under the provisions of the Price Anderson Act, if third-party claims relating to such an incident exceed $200 million (the amount of primary insurance), DPL could be assessed up to $26.3 million on an aggregate basis for such third-party claims. In addition, Congress could impose a revenue-raising measure on the nuclear industry to pay such claims.

The co-owners of Peach Bottom and Salem maintain property insurance coverage of approximately $2.8 billion for each unit for loss or damage to the units, including coverage for decontamination expense and premature decommissioning. In addition, DPL is a member of an industry mutual insurance company, which provides replacement power cost coverage in the event of a major accidental outage at a nuclear power plant. Under these coverages, DPL is subject to potential retrospective loss experience assessments of up to $4.0 million on an aggregate basis.

20. Quarterly Financial Information (unaudited)

The quarterly data presented below reflect all adjustments necessary in the opinion of DPL for a fair presentation of the interim results. Quarterly data normally vary seasonally because of temperature variations, differences between summer and winter rates, the timing of rate orders, and the scheduled downtime and maintenance of electric generating units.

Quarter Ended	Operating Revenue	Operating Income	Net Income (Loss)	Applicable to Common Stock
		(Dollars in Thousands)		
1998				
March 31	$ 416,110	$ 13,089	$ (4,856)	$ (5,942)
June 30	362,378	78,337	33,075	31,989
September 30	598,888	129,076	66,737	65,650
December 31	522,523	44,925	17,454	16,361
	$1,899,899	$265,427	$112,410	$108,058
1997				
March 31	$ 346,079	$ 63,150	$ 25,793	$ 24,578
June 30	310,968	51,376	17,997	16,913
September 30	400,502	85,509	39,411	38,319
December 31	357,818	26,259	22,508	21,408
	$1,415,367	$226,294	$105,709	$101,218

Employee separation programs for DPL employees and other Merger-related costs expensed in 1998 (as discussed in Note 4 to the Consolidated Financial Statements) had the effects shown below on 1998 quarterly operating results.

1998 Quarter Ended	Operating Income	Net Income
	(Dollars in Millions)	
March 31	$(40.3)	$(24.4)
June 30	14.3	8.6
September 30	(0.7)	(0.4)
December 31	(0.7)	(0.4)
	$(27.4)	$(16.6)

As discussed in Note 5 to the Consolidated Financial Statements, in the fourth quarter of 1997, net income was increased by $13.7 million due to the sale of the Pine Grove Landfill and its related waste-hauling company.

21. Segment Information

Conectiv's organizational structure and management reporting information is aligned with Conectiv's business segments, irrespective of which subsidiary, or subsidiaries, a business is conducted through. Businesses are managed based on lines of business, not based on legal entity. Business segment information is not produced, or reported, on a subsidiary by subsidiary basis. Thus, as a Conectiv subsidiary, no business segment information (as defined by SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information") is available for DPL on a stand-alone basis.

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

None.

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PART III

Item 10. Directors and Executive Officers of the Registrant

Directors	Business Experience during Past 5 Years
As of December 31, 1998	
Howard E. Cosgrove, 55, ... Chairman of the Board	Elected 1998 as Chairman of the Board and Chief Executive Officer of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Elected 1992 as Chairman of the Board, President and Chief Executive Officer and Director of Delmarva Power & Light Company.
Meredith I. Harlacher, Jr., 56, ... Director	Elected 1998 as President and Chief Operating Officer of Conectiv, and President and Chief Operating Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1993 as Senior Vice President of Atlantic Energy, Inc.
Thomas S. Shaw, 51, ... Director	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1992 as Senior Vice President, Delmarva Power & Light Company.
Barry R. Elson, 57, ... Director	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1997 as Executive Vice President, Delmarva Power & Light Company. Executive Vice President, Cox Communications, Inc., Atlanta, Georgia, from 1995 to 1996. Senior Vice President, Cox Enterprises/Cox Communications, Inc., Atlanta, Georgia, from 1984 to 1995.
Barbara S. Graham, 50, ... Director	Elected 1998 as Senior Vice President and Chief Financial Officer of Conectiv, and Senior Vice President and Chief Financial Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1994 as Senior Vice President, Treasurer, and Chief Financial Officer, Delmarva Power & Light Company. Vice President and Chief Financial Officer from 1992 to 1994.
Audrey K. Doberstein, 66, ... Director	Director of Delmarva Power & Light Company since 1992. Elected 1998, Director of Conectiv. President of Wilmington College, New Castle, Delaware. Dr. Doberstein also serves as a member of the Board of Directors of Blue Cross/Blue Shield of Delaware and Mellon Bank Delaware (N.A.), Wilmington, Delaware.
Jerrold L. Jacobs, 59, ... Director	Elected 1998, Director of Conectiv and Delmarva Power & Light Company. Director of Atlantic Energy since 1990. Retired, Chairman of the Board and Chief Executive Officer of Atlantic Energy and of Atlantic City Electric Company.

Executives

Information about DPL's executive officers is included under Item 1.

Item 11. Executive Compensation

As previously noted, DPL is a wholly owned electric utility subsidiary of Conectiv. The Chief Executive Officer and the four most highly compensated executive officers of Conectiv maintain the same position at both DPL and ACE. In 1998, the salaries and other compensation awarded to the Chief Executive Officer and the four most highly compensated executive officers of DPL were paid by Conectiv for their service as executive officers of Conectiv, DPL and ACE. The Board Personnel & Compensation Committee Report was provided initially in the Conectiv Proxy Statement and is enclosed herein for the purpose of providing additional informational. The following tables show information concerning the total compensation paid or awarded to DPL's Chief Executive Officer and each of the four most highly compensated executive officers for the fiscal year ended December 31, 1998.

BOARD PERSONNEL & COMPENSATION COMMITTEE REPORT

Principles of Executive Compensation Program

The Personnel & Compensation Committee of the Board of Directors is comprised of four non-employee Directors. The Committee provides an independent review of the Company's performance objectives and executive compensation.

Overall Objectives

The Company's philosophy is to link compensation to business strategies and results, to align total compensation of executives with the long-term interests of stockholders, to motivate its senior executives to meet the challenging objectives established for the Company and to create an urgency for success in the newly-formed Company. The Company's executive compensation program is designed to:

- provide total compensation that emphasizes long-term performance which creates stockholder value;
- facilitate the rapid transition to a competitive business environment;
- reflect the market conditions for attracting and retaining high-quality executives and ensure that such executives have a continuing stake in the long-term success of the Company; and
- create significant levels of stock ownership.

The elements of the executive compensation program are:

- total compensation levels that are competitive with those provided by the competitive market, defined as a blend of companies in the utility and industrial markets;
- base compensation levels related to responsibility level and individual performance;
- annual variable compensation that varies based on corporate, unit and individual performance; and,
- long-term variable compensation based on long-term increases in stockholder value.

Total Compensation

Total compensation opportunities are developed for Company executives by Watson Wyatt, the firm that provides executive compensation consulting services to the Company. This is done using several published compensation survey sources and public proxy data to define the competitive market. Overall, the total compensation structure for executives is targeted at the median for similar positions at companies of similar size, including both utilities and industrial companies (Compensation Comparison Group)[1]. Individual reward levels

1. The Compensation Comparison Group does not include all of the same companies as the published industry indices in the Comparison of 10 Month Cumulative Total Return chart included in this Proxy Statement. However, 34 of the 85 companies included in the EEI *Executive Compensation Report,* which is one element of the Compensation Comparison Group, are also part of either the Dow Jones Electric Utilities Index or the S&P 500 Index.

vary based on individual contributions and performance. Total compensation includes three components: base compensation, annual variable compensation and long-term variable compensation. The targets for each component of the executive compensation program are reviewed on an annual basis to ensure alignment with the Company's compensation philosophy and a proper balance between short-and long-term objectives.

Base Compensation

Base compensation for executive officers is determined by evaluating the responsibilities of the positions held and the experience of the individuals, coupled with a review of compensation for comparable positions at other companies. Base compensation is reviewed on an annual basis and adjustments are based on the performance of the Company and each executive officer. Annual base compensation increases reflect the individual's performance and contribution over several years in addition to the results for a single year. Following the 1998 increases, the overall base compensation level for the five named executive officers was slightly below the median of the base compensation targeted levels defined by the surveys and proxies.

Annual Variable Compensation

The Company's annual variable compensation is designed to motivate participants to accomplish stretch financial and individual goals and to increase the sense of urgency to deliver significant results on an annual basis. Annual variable compensation target opportunities are designed to be at or above the median of the blended utility and industrial market and for the named executive officers vary from 40% to 50% of base compensation, with maximum awards of 60% to 75% of base compensation.

Annual variable compensation is paid in a combination of cash (80%) and restricted stock units (20%) and is based on the achievement of predetermined corporate and individual goals. The plan for 1998 provides that payouts will occur only after a specified earnings target is achieved.

For 1998, each individual covered by the plan was eligible to earn a variable compensation award between 0% and 150% of target. The portion of each individual award attributable to corporate, line of business, and group performance were determined and specific measures were developed at the beginning of the year. These measures were primarily financial for 1998 to accelerate the transition of the Company to a more competitive environment and included corporate measures of earnings, cash flow return on capital employed and cash flow. Each business group and line of business also developed specific financial measures to support their business plans.

The Management Stock Purchase Program (MSPP) was designed as a means to promote significant executive stock ownership in the new company and to help meet stock ownership guidelines. The program requires that 20% of the individual's earned annual variable compensation must be used to acquire restricted stock units (RSUs). Individuals may also voluntarily use up to an additional 30% (for a total of 50%) of their earned annual variable compensation to acquire RSUs. All RSUs are acquired at a 20% discount from Fair Market Value on the date paid. Each RSU is a proxy for one share of Common Stock, has a value equal to one share and earns at the rate of the Common Stock dividend. RSUs are restricted from sale or use for a 3-year period and are distributed in shares of Common Stock.

Long-Term Variable Compensation

The Company's long-term variable compensation reinforces the importance of providing stockholders with a competitive return on their investment. Long-term variable compensation awards also strengthen the ability of the Company to attract, motivate and retain executives of superior capability and more closely align the interests of management with those of stockholders.

Long-term grants for Conectiv executives are determined by setting a target percentage of base compensation based on median data in the Compensation Comparison Group and converting the target amounts to actual grants using the "Black-Scholes Model" for options and time and forfeiture discount methods for the other elements of the long-term grants.

Long-term awards granted in 1998 consisted of non-qualified stock options, dividend equivalent units and performance accelerated restricted stock. Non-qualified stock options and dividend equivalent units were awarded to provide approximately two-thirds of the targeted value of the grant while the other one-third of the targeted value was provided through performance accelerated restricted stock. This stock vests as unrestricted Common Stock seven years from the award date. However, vesting may be accelerated if the price of Common Stock reaches certain predetermined levels prior to the seven years. All stock options were granted with exercise prices equal to the fair market value of Common Stock at the time of the grant.

Performance accelerated restricted stock granted to the CEO and three other named executive officers is also subject to an additional condition tied to Total Shareholder Return over the seven year period. Failure to meet a predetermined Total Shareholder Return level over the restriction period will result in total forfeiture of their shares granted.

The CEO and three other named executive officers also were given a special grant of performance accelerated stock options to increase emphasis on creating long-term shareholder value. All performance accelerated stock options were granted with exercise prices equal to the fair market value of Common Stock at the time of grant. These options do not vest and cannot be exercised for 9-1/2 years from the date of their grant unless the stock price increases to predetermined levels. Absent accelerated vesting at these predetermined stock prices, the shares will become exercisable in 9-1/2 years with expiration occurring at 10 years. This special grant resulted in the long-term variable compensation component and total compensation exceeding the targeted median values for these four executives for 1998 using the Black-Scholes valuation methodology.

Stock Ownership Guidelines

To further reinforce the interests of stockholders, stock ownership guidelines have been established for the Board of Directors, Company officers, and other Company management. These guidelines require the individuals covered by the guidelines to have beneficial ownership of Common Stock, or securities convertible into Common Stock, with an aggregate value equal to certain multiples of each individual's salary (or annual retainers in the case of outside directors). Multiples range from five times to one times salary. The Chief Executive Officer's multiple is set at five times salary and outside Directors' multiples are set at three times the annual retainer.

Internal Revenue Code Section 162(m)

The Committee considers the tax deductibility of compensation paid to executive officers and the impact of Section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code"), on the Company. This provision limits the amount of compensation that the Company may deduct from its taxable income for any year to $1 million for any of its five most highly compensated executive officers, unless certain requirements are met.

The Committee has taken actions to limit the impact of the Code in the event that compensation paid to a named executive officer might otherwise not be deductible. The Committee will continue to seek ways to limit the impact of the Code; however, the Committee believes that the tax deduction limitation should not compromise the Company's ability to create incentive programs that support the business strategy and also attract and retain the executive talent required to compete successfully. Accordingly, achieving the desired flexibility in the design and delivery of compensation may periodically result in some compensation that is not deductible for federal income tax purposes.

Summary of Actions Taken by the Personnel & Compensation Committee

The Personnel & Compensation Committee, consisting entirely of outside directors, provides direction and oversight to the Company's executive compensation plans, establishes the Company's compensation philosophy and assesses the effectiveness of the program as a whole. This includes activities such as reviewing the design of various plans and assessing the reasonableness of the total program consistent with the total compensation philosophy.

Annual Variable Compensation

To provide clear focus on increasing stockholder value through the successful completion of the Merger and growing the new Conectiv businesses, Mr. Cosgrove received additional levels of long-term awards in place of an annual variable opportunity for 1997. Therefore, there is no annual variable pay for 1997 reflected in 1998 compensation.

Mr. Cosgrove's annual variable compensation target opportunity for 1998 was set at 50% of base compensation, with a minimum payout of 0% and a maximum payout of 75% of base compensation. Payment of any award requires achieving a predetermined level of 1998 earnings established by this Committee. Performance measures for 1998, predetermined by this Committee, included earnings available for common stock, cash flow return on capital employed and cash flow. Awards for 1998 for Mr. Cosgrove and the four other named executive officers have not been determined.

Long-Term Variable Compensation

Long-term incentive grants are a critical component of the Conectiv executive compensation philosophy, since they align executive interests very clearly with increased stockholder value. For 1998, Mr. Cosgrove received grants of non-qualified stock options, dividend equivalent units, performance accelerated restricted stock, and performance accelerated stock options (reflected in the Compensation Tables). The regular grants of non-qualified stock options, dividend equivalent units and performance accelerated restricted stock provided a long-term variable compensation opportunity approximately at the median of the defined competitive market.

The special, non-recurring grant of performance accelerated stock options was awarded to create additional emphasis on achieving higher levels of stockholder value. In order for Mr. Cosgrove to receive any value from this grant prior to vesting at nine and one-half years, there must be a significant increase in stockholder value. Such increases prior to nine and one-half years will result in accelerated vesting of this grant in increments of one-third. The first third would vest when stockholder value increases by $400,000,000, at which time Mr. Cosgrove's options would vest at a value of $1,200,000, or .3% of the increase in stockholder value. The entire grant would vest if stockholder value increases by $800,000,000, at which time Mr. Cosgrove's options would vest at a value of $2,400,000 or .3% of the increase in stockholder value. Only under results that yield increases in stockholder value and trigger accelerated vesting of this grant would Mr. Cosgrove's 1998 compensation exceed the median target compensation level.

Personnel & Compensation Committee

S.I. Gore, Chairperson
M.B. Emery
R.B. McGlynn
B.J. Morgan

The Committee also assists in administering key aspects of the Company's annual compensation program and variable compensation plan, such as reviewing annual compensation budgets and setting targets and corporate performance measures for the annual and long-term variable compensation plans.

Finally, the Committee specifically implements the Company's executive compensation program as it directly pertains to the Chief Executive Officer and the Company's four other most highly compensated executives, *i.e.*, the five "named executive officers."

The Committee has determined that in an environment where competition is increasing, it is essential that the Company have the ability to attract, motivate and retain high quality executives from within and outside the utility industry.

Because of the extremely competitive market for executive talent, the Personnel & Compensation Committee has adopted a compensation structure based on a blend of utility and general competitive industry markets. The structure is also flexible to allow setting salaries at pure general industry levels where that may be necessary to attract certain specific skills and experience.

Consistent with this approach, the total compensation program relies on competitive base compensation generally at or below the median of the market with annual and long-term variable compensation opportunities generally above the median of the market. This places a much greater emphasis on variable compensation that aligns executive and stockholder interests.

This total compensation philosophy is important to the success of the Company because the Company is facing increasing competition and related risks. The Company is not simply a utility anymore, but is rapidly becoming part of the general competitive industry market and, therefore, just as strategies for success must change, the compensation to drive success must also change. Prior to the Merger involving Atlantic Energy and Delmarva and during 1998, this compensation philosophy enabled the Company to attract several key executives with experience and skills critical to the emerging competitive environment. These executives would not have been available under a traditional utility compensation philosophy.

Significant actions by the Committee for fiscal year 1998 included adoption of the new Conectiv executive plans (Conectiv Variable Compensation Plan, Deferred Compensation Plan, Supplemental Executive Retirement Plan [SERP], and Change In Control Agreements) and other compensation and benefit plans for Conectiv employees. The Committee also sets base compensation, annual variable targets and performance measures and long-term grants under the various executive programs, including special awards of performance accelerated stock options to the CEO and the three other named executive officers described above.

Chief Executive Officer Compensation

Mr. Cosgrove's compensation reflects Conectiv's compensation philosophy. His base compensation, annual and regular long-term variable compensation place him at total compensation levels consistent with the median level of other CEO's at similarly-sized utility and manufacturing companies represented in the Compensation Comparison Group. Additional emphasis on achieving increased stockholder value has been created with a special grant of performance accelerated stock options. This special grant will cause his long term compensation and total compensation to exceed the median targets for 1998.

Base Compensation Action

Conectiv was formed by a Merger involving Delmarva and Atlantic Energy in early 1998. Mr. Cosgrove's base compensation was set during the Merger process to reflect the size of Conectiv and the increasing competitive environment in which Conectiv does business. His 1998 base compensation is at the median target level developed through a comparison of other Chief Executive Officers of similarly-sized corporations using a blend of utilities and general industry. His salary for 1999 will remain the same as in 1998.

Personnel & Compensation Committee Interlocks and Insider Participation

The Personnel & Compensation Committee is comprised solely of non-officer directors. Logical Business Solutions, which is owned by Mr. Emery's son-in-law, Paul Kleiman, had contracts with Conectiv Resource Partners, Inc., a subsidiary of the Company, with a gross value of $227,000 during 1998 for information technology consulting services. Except as described in the preceding sentence, there are no Personnel & Compensation Committee interlocks.

Table 1 — Summary Compensation Table

			Annual Compensation		Long-Term Compensation			
					Awards	Payouts		
Name and Principal Position	Year (1)	Annualized Salary	Variable Compensation (Bonus)(2)	Other Annual Compensation	Restricted Stock	Securities Underlying Options	LTIP Payouts (3)	All Other Compensation (4)
H.E. Cosgrove,	1998	$ 600,000	0	0	0	360,000	$572,134	$12,329
Chairman of the Board and	1997	$ 400,000	0	0	0	0	0	$18,981
Chief Executive Officer	1996	$ 400,000	0	0	0	0	0	$18,115
M.I. Harlacher,	1998	$340,000	0	0	0	0	0	$ 3,742
President								
B.R. Elson,	1998	$ 325,000	0	0	0	170,000	$ 21,560	$ 4,074
Executive Vice President								
T.S. Shaw,	1998	$ 325,000	0	0	0	170,000	$155,267	$ 9,478
Executive Vice	1997	$ 219,249	$27,100	0	0	0	0	$ 6,563
President	1996	$ 180,000	$52,300	0	0	0	0	$ 6,333
B.S. Graham,	1998	$ 250,000	0	0	0	170,000	$155,267	$ 5,308
Senior Vice President	1997	$ 184,000	$27,100	0	0	0	0	$ 3,390
	1996	$ 180,000	$92,300	0	0	0	0	$ 5,529

(1) Base salary is shown as an annualized amount. Other items of compensation reflect the full calendar 1998 compensation received from Conectiv and either Delmarva or Atlantic City Electric Company.

(2) The 1998 bonus, which is an annual variable award, has not yet been determined. The target award is 50% of annualized salary for Mr. Cosgrove and 40% for Messrs. Harlacher, Elson and Shaw and Mrs. Graham.

(3) During 1998 all restrictions lapsed on the performance-based restricted stock granted in 1995 and 1996 under the Delmarva LTIP due to the Merger involving Delmarva and Atlantic Energy. Under the ''change in control'' provisions, the awards fully vested resulting in a payout to Mr. Cosgrove of 21,160 shares (11,570 for 1995 and 9,590 for 1996) valued at $454,940; to Mr. Shaw of 5,450 shares (2,870 for 1995 and 2,580 for 1996) valued at $117,175; and to Mrs. Graham of 5,450 shares (2,870 for 1995 and 2,580 for 1996) valued at $117,175. Shares were valued at $21.50 at the time of payout. Dividends on shares of restricted stock and dividend equivalents are accrued at the same rate as that paid to all holders of Common Stock. As of December 31, 1998; Mr. Cosgrove held 45,520 shares of restricted stock (35,520 for 1997 and 10,000 for 1998) and 30,000 Dividend Equivalent Units (''DEU's''); Mr. Elson held 4,000 shares of restricted stock for 1998 and 10,000 DEU's; Mr. Shaw held 12,010 shares of restricted stock (8,010 for 1997 and 4,000 for 1998) and 10,000 DEU's; Mrs. Graham held 12,010 shares of restricted stock (8,010 for 1997 and 4,000 for 1998) and 10,000 DEU's. Holders of restricted stock are entitled to receive dividends as declared.

(4) The amount of All Other Compensation for each of the named executive officers for fiscal year 1998 include the following: Mr. Cosgrove, $2,125 in Company matching contributions to the Company's Savings and Investment Plan, $10,000 in Company matching contributions to the Company's Deferred Compensation Plan and $204 in term life insurance premiums paid by the Company; for Mr. Shaw, $2,630 in Company

matching contributions to the Company's Savings and Investment Plan, $6,644 in Company matching contributions to the Company's Deferred Compensation Plan and $204 in term life insurance premiums paid by the Company; for Mrs. Graham, $2,604 in Company matching contributions to the Company's Savings and Investment Plan, $2,500 in Company matching contributions to the Company's Deferred Compensation Plan and $204 in term life insurance premiums paid by the Company; for Mr. Elson, $2,969 in Company matching contributions to the Company's Savings and Investment Plan and $1,105 in term life insurance premiums paid by the Company; and for Mr. Harlacher, $3,300 in Company matching contributions to the Company's Savings and Investment Plan and $442 in term life insurance premiums paid by the Company.

Table 2 — Option Grants in Last Fiscal Year (1)

Name	Number of Securities Underlying Options Granted (#)	% of Total Options Granted to Employees in Fiscal Year	Exercise Price ($/Sh)	Expiration Date	Grant Date Present Value(4)
H.E. Cosgrove.	300,000(2)	29%	$22.84375	1/2/08	$385,831
	60,000(3)	6%	$22.84375	1/2/08	$137,063
M.I. Harlacher	—	0%	—	—	—
	—	0%	—	—	—
B.R. Elson	150,000(2)	14%	$22.84375	1/2/08	$192,915
	20,000(3)	2%	$22.84375	1/2/08	$ 45,688
T.S. Shaw	150,000(2)	14%	$22.84375	1/2/08	$192,915
	20,000(3)	2%	$22.84375	1/2/08	$ 45,688
B.S. Graham	150,000(2)	14%	$22.84375	1/2/08	$192,915
	20,000(3)	2%	$22.84375	1/2/08	$ 45,688

(1) Currently, Delmarva does not grant stock appreciation rights. The options reflected in this table are for payouts in shares of Conectiv Common Stock.

(2) Denotes Performance Accelerated Stock Options (''PASO's'') which were granted on a one-time basis. PASO's have a ten-year term and vest and are first exercisable 9 and 1/2 years from date of grant without regard to stock price performance. Exercise date will accelerate for favorable stock price performance (i.e., first 1/3, second 1/3 and third 1/3 of PASO's vest after stock trades at $26, $28 or $30 per share, respectively, for ten consecutive trading days). There is a minimum holding period of three years from date of grant during which these options are not exercisable.

(3) Denotes Nonqualified Stock Options. One-half of such Options vest and are exercisable at end of second year from date of grant. Second one-half vest and are exercisable at end of third year from date of grant.

(4) Determined using the Black-Scholes model, incorporating the following material assumptions and adjustments: (a) exercise price of $22.84375, equal to the Fair Market Value (''FMV'') as of date of grant; (b) an option term of ten years; (c) risk-free rate of return of 6.00%; (d) volatility of 20.00%; and (e) dividend yield of 7.00%. For valuation purposes, PASO's are valued as a premium-priced stock option as of the date of grant with an exercise price of $30 on a FMV of $22.84375.

Table 3 — Aggregated Option Exercises in Last Fiscal Year and FY-End Option Values

Name	Shares Acquired on Exercise	Value Realized ($)(1)	Number of Securities Underlying Unexercised Options at FY-End(2) Exercisable/Unexercisable	Value of Unexercised In-the-Money Options at FY-End(1)
H. E. Cosgrove	0	0	14,400/360,000	$51,225/$596,250
M. I. Harlacher	0	0	—	$ —
B. R. Elson	0	0	0/170,000	$ 0/$281,563
T. S. Shaw	0	0	0/170,000	$ 0/$281,563
B. S. Graham	0	0	0/170,000	$ 0/$281,563

(1) The closing price for Conectiv's common stock as reported by the New York Stock Exchange on December 31, 1998 was $24.50. Any value in the options would be based on the difference between the exercise price of the options and the value at the time of the exercise (e.g., $24.50 as of close of business on 12/31/98), which difference would be multiplied by the number of options exercised.

(2) Only 14,400 stock options of Mr. Cosgrove are currently exercisable. None of the remaining options may be exercised earlier than two years from date of grant for regular, non-performance based options and nine and one half years from date of grant for performance based options (subject to accelerated vesting for favorable stock price performance).

Table 4 — Long-Term Incentive Plans—Awards in Last Fiscal Year

Name	Number of Restricted Shares/Dividend Equivalent Units (#)(1)	Performance Period Until Maturation or Payout(2)
H. E. Cosgrove	10,000 shs/30,000 units	3/2/05
M. I. Harlacher	—	—
B. R. Elson	4,000 shs/10,000 units	3/2/05
T. S. Shaw	4,000 shs/10,000 units	3/2/05
B. S. Graham	4,000 shs/10,000 units	3/2/05

(1) In addition, Mr. Cosgrove held 35,520 performance shares (valued at $870,240) and Mr. Shaw and Mrs. Graham held 8,010 performance shares (valued at $196,245) from a 1997 award with a four year performance cycle under the Delmarva Power Long Term Incentive Plan.

(2) Awards of Restricted Shares (Performance Accelerated Restricted Stock or "PARS") and Dividend Equivalent Units ("DEU's") were made to four of the named executive officers. The payout of shares of PARS may potentially be "performance accelerated." Restrictions may lapse any time after 3 years (i.e., after March 1, 2001) upon on achievement of favorable stock price performance goals. In the absence of such favorable performance, restrictions lapse after 7 years (i.e., March 2, 2005) provided that at least a defined level of average, total return to shareholders is achieved. As of December 31, 1998, Mr. Cosgrove's 10,000 Restricted Shares were valued at $245,000 and Messrs. Elson and Shaw and Mrs. Graham's 4,000 PARS were valued at $98,000. These values for both Restricted Shares and performance shares are based on the December 31, 1998 closing stock price of $24.50. For Dividend Equivalent Units, one DEU is equal in value to the regular quarterly dividend paid on one share of Conectiv common stock. The Dividend Equivalent Units shown are payable in cash for twelve quarters over a three year period ending with the quarterly dividend equivalent payable January 31, 2001. At that point, the 1998 DEU award lapses.

Pension Plan

The Conectiv Retirement Plan includes the Cash Balance Pension Plan and grandfathered provisions relating to the Delmarva Retirement Plan and the Atlantic Retirement Plan that apply to employees who had either 20 years of service or were age 50 on the effective date of the Cash Balance Pension Plan (January 1, 1999). Certain executives whose benefits from the Conectiv Retirement Plan are limited by the application of Federal tax laws also receive benefits from the Supplemental Executive Retirement Plan.

Cash Balance Pension Plan

The named executive officers participate in the Conectiv Retirement Plan and earn benefits that generally become vested after five years of service. On an annual basis, a recordkeeping account in a participant's name is credited with an amount equal to a percentage of the participant's total pay, including base salary, overtime and bonuses, depending on the employee's age at the end of the plan year, as follows:

Age at end of Plan Year	% of Pay
Under 30	5
30 to 34	6
35 to 39	7
40 to 44	8
45 to 49	9
50 and over	10

These accounts also receive interest credits based on average U.S. Treasury Bill rates for the year. In addition, certain annuity benefits earned by participants under the former Delmarva and Atlantic Retirement Plans are fully protected as of December 31, 1998, and will be converted to an equivalent cash amount and included in each employee's initial cash balance account. When an employee terminates employment, the amount credited to his or her account is converted into an annuity or paid in a lump sum.

Supplemental Retirement Benefits

Supplemental retirement benefits are provided to certain employees, including each executive officer, whose benefits under the Conectiv Retirement Plan are limited by type of compensation or amount under applicable Federal tax laws and regulations. Designated employees may also receive an annual benefit at retirement equal to a percentage of final average compensation multiplied by years of service reduced by the amount of all benefits received under the Conectiv Retirement Plan and other nonqualified arrangements.

Estimated Retirement Benefits Payable to Named Executive Officers

The following table shows the estimated retirement benefits, including supplemental retirement benefits under the plans applicable to the named executive officers, which would be payable if he or she were to retire at normal retirement age, which is age 65, at 1998 compensation, expressed in the form of a lump sum payment. Years of service credited to each named executive officer as of his or her normal retirement date are as follows: Mr. Cosgove, 42; Ms. Graham, 30; Mr. Shaw, 40; Mr. Elson, 16 (8 of which are additional years of service for purposes of the supplemental retirement benefits), and Mr. Harlacher, 43.

Estimated Retirement Benefits

Name	Year of 65th Birthday	Lump Sum Value
H. E. Cosgrove	2008	$2,993,000(2)
B. S. Graham	2013	1,540,000(1)
T. S. Shaw	2012	1,789,000(2)
B. R. Elson	2006	1,213,000(2)
M. I. Harlacher	2007	2,323,000(2)

(1) Amounts include (i) interest credits for cash balances projected to be 5.01% per annum on annual salary credits and prior service balances, if any, and (ii) accrued benefits as of December 31, 1998 under retirement plans then applicable to the named executive officer. Benefits are not subject to any offset for Social Security payments or other offset amounts and assume no future increases in base salary or total pay.

(2) Under the Conectiv Retirement Plan's grandfather provisions, employees who participated in the Delmarva or Atlantic Retirement Plans and who met certain age and service requirements as of December 31, 1998, will have retirement benefits for all years of service up to retirement calculated according to their original final pay formula benefit. This benefit will be compared to the cash balance account and the employee will receive whichever is greater. Estimated benefits are based on the Delmarva Retirement Plan for Messrs. Cosgrove, Shaw and Elson, the Cash Balance Pension Plan for Mrs. Graham and the Atlantic Retirement Plan for Mr. Harlacher. The amount of benefit under such grandfathering is illustrated in the following tables applicable to the Delmarva and Atlantic Retirement Plans, respectively:

Delmarva Retirement Plan
Pension Plan Table
Annual Retirement Benefits in Specified Remuneration and Years of Service Classifications

Average Annual Earnings for the 5 Consecutive Years of Earnings that Result in the Highest Average	15 Yrs.	20 Yrs.	25 Yrs.	30 Yrs.	35 Yrs.
$125,000	28,599	38,132	47,665	57,198	66,732
200,000(1)	46,599	62,132	77,665	93,198	108,732
300,000(1)	70,599	94,132	117,665	141,198(2)	164,732(2)
400,000(1)	94,599	126,132	157,665(2)	189,198(2)	220,732(2)
500,000(1)	118,599	158,132(2)	197,665(2)	237,198(2)	276,732(2)

(1) Effective January 1, 1998, annual compensation recognized may not exceed $160,000.

(2) For 1998, the limit on annual benefits is $130,000.

Benefits are payable in the form of a 50% joint and surviving spouse annuity or lump sum and earnings include base salary, overtime and bonus.

Atlantic Retirement Plan Pension Plan Table
Annual Retirement Benefits in Specified Remuneration and Years of Service Classifications

Average Annual Earnings for the 5 Consecutive Years of Earnings that result in the Highest Average	15 Yrs.	20 Yrs.	25 Yrs.	30 Yrs.	35 Yrs.
$125,000	30,000	40,000	50,000	60,000	70,000
200,000(1)	48,000	64,000	80,000	96,000	112,000
300,000(1)	72,000	96,000	120,000	144,000(2)	168,000(2)
400,000(1)	96,000	128,000	160,000(2)	192,000(2)	224,000(2)
500,000(1)	120,000	160,000(2)	200,000(2)	240,000(2)	280,000(2)

(1) Effective January 1, 1998, annual compensation recognized may not exceed $160,000.

(2) For 1998, the limit on annual benefits is $130,000.

Benefits are paid in the form of a life annuity or lump sum and earnings include base salary and bonus.

Change in Control Severance Agreements And Other Provisions Relating to Possible Change in Control

Conectiv has entered into change in control severance agreements with Messrs. Cosgrove, Elson and Shaw and Mrs. Graham and two other senior executives. The agreements are intended to encourage the continued dedication of members of Conectiv's senior management team. These agreements provide potential benefits for such executives upon actual or constructive termination of employment (other than for cause) following a change in control of Conectiv, as defined in such agreements. Each affected executive would receive a severance payment equal to three times Base Salary and Bonus and Conectiv-paid medical, dental, vision, group life and disability benefits during the three years after termination of employment, and a cash payment equal to the actuarial equivalent of accrued retirement pension credits equal to 36 months of additional service.

In the event of a change in control, the Variable Compensation Plan provides that outstanding options become exercisable in full immediately, all conditions to the vesting of PARS are deemed satisfied and shares will be fully vested and nonforfeitable, DEU's will become fully vested and be immediately payable, variable compensation deferred under the Management Stock Purchase Program will be immediately distributed, and payment of variable compensation, if any, for the current year will be decided by the Board's Personnel & Compensation Committee. For the Deferred Compensation Plan, the Committee may decide to distribute all deferrals in cash immediately or continue the deferral elections of participants in which event Conectiv will fully fund a ''springing rabbi trust'' to satisfy the obligations. An independent institutional trustee will maintain any such trust established by reason of this provision.

Item 12. Security Ownership of Certain Beneficial Owners and Management

All shares of DPL's common stock are owned by Conectiv, DPL's parent company.

Item 13. Certain Relationships and Related Transactions

None.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. Financial Statements—The following financial statements are contained in Item 8 of Part II.

	Page No.
Report of Independent Accountants	II-15
Consolidated Statements of Income for the years ended December 31, 1998, 1997 and 1996	II-16
Consolidated Statements of Cash Flows for the years ended December 31, 1998, 1997, and 1996	II-17
Consolidated Balance Sheets as of December 31, 1998 and 1997	II-18
Consolidated Statements of Changes in Common Stockholder's Equity for the years ended December 31, 1998, 1997, and 1996	II-20
Notes to Consolidated Financial Statements	II-21

2. Financial Statement Schedules—No financial statement schedules have been filed since the required information is not present in amounts sufficient to require submission of the schedule or because the information required is included in the respective financial statements or the notes thereto.

3. Schedule of Operating Statistics for the three years ended December 31, 1998 can be found on pages IV-4 and IV-5 of this report.

4. Exhibits

Exhibit Number	
2	Amended and Restated Agreement and Plan of Merger, dated as of December 26, 1996, between DPL, Atlantic Energy, Inc., Conectiv, Inc. and DS Sub, Inc. (Filed with Registration Statement No. 333-18843.)
3-A	Copy of the Restated Certificate and Articles of Incorporation effective as of April 12, 1990. (Filed with Registration Statement No. 33-50453.)
3-B	Copy of DPL's Certificate of Designation and Articles of Amendment establishing the 7¾% Preferred Stock—$25 Par. (Filed with Registration Statement No. 33-50453.)
3-C	Copy of DPL's Certificate of Designation and Articles of Amendment establishing the 6¾% Preferred Stock. (Filed with Registration Statement No. 33-53855.)
3-D	A copy of DPL's Certificate of Amendment of Restated Certificate and Articles of Incorporation, filed with the Delaware Secretary of State, effective as of June 7, 1996. (Filed with Registration No. 333-07281.)
3-E	A copy of DPL's Articles of Amendment of Restated Certificate and Articles of Incorporation, filed with the Virginia State Corporation Commission, effective as of June 7, 1996. (Filed with Registration No. 333-07281.)
3-F	A copy of DPL's Certificate and Articles of Amendment of Restated Certificate and Articles of Incorporation, filed with the Delaware Secretary of State, effective as of March 2, 1998 (filed with DPL's Current Report on Form 8-K dated March 4, 1998; File No. 1-1405).
3-G	A copy of DPL's Articles of Amendment of Restated Certificate and Articles of Incorporation, filed with the Virginia State Corporation Commission, effective as of March 2, 1998 (filed with DPL's Current Report on Form 8-K dated March 4, 1998; File No. 1-1405).

Exhibit Number	
3-H	Certificate of Merger of DS Sub, Inc., a Delaware Corporation with and into DPL, filed with the Delaware Secretary of State, effective as of March 1, 1998 (filed with DPL's Current Report on Form 8-K dated March 4, 1998; File No. 1-1405).
3-I	Certificate of Merger of DS Sub, Inc., a Delaware Corporation with and into DPL, filed with the Virginia State Corporation Commission, effective as of March 1, 1998 (filed with DPL's Current Report on Form 8-K dated March 4, 1998; File No. 1-1405).
3-J	Copy of DPL's By-Laws as amended March 2, 1998 (filed with DPL's Current Report on Form 8-K dated March 4, 1998; File No. 1-1405).
4-A	Copy of the Mortgage and Deed of Trust of Delaware Power & Light Company to the New York Trust Company, Trustee, (the Chase Manhattan Bank, successor Trustee) dated as of October 1, 1943 and copies of the First through Sixty-Eighth Supplemental Indentures thereto. (Filed with Registration Statement No. 33-1763.)
4-B	Copy of the Sixty-Ninth Supplemental Indenture. (Filed with Registration Statement No. 33-39756.)
4-C	Copies of the Seventieth through Seventy-Fourth Supplemental Indentures. (Filed with Registration Statement No. 33-24955.)
4-D	Copies of the Seventy-Fifth through the Seventy-Seventh Supplemental Indentures. (Filed with Registration Statement No. 33-39756.)
4-E	Copies of the Seventy-Eighth and Seventy-Ninth Supplemental Indentures. (Filed with Registration Statement No. 33-46892.)
4-F	Copy of the Eightieth Supplemental Indenture. (Filed with Registration Statement No. 33-49750.)
4-G	Copy of the Eighty-First Supplemental Indenture. (Filed with Registration Statement No. 33-57652.)
4-H	Copy of the Eighty-Second Supplemental Indenture. (Filed with Registration Statement No. 33-63582.)
4-I	Copy of the Eighty-Third Supplemental Indenture. (Filed with Registration Statement No. 33-50453.)
4-J	Copies of the Eighty-Fourth through Eighty-Eighth Supplemental Indentures. (Filed with Registration Statement No. 33-53855.)
4-K	Copies of the Eighty-Ninth and Ninetieth Supplemental Indentures. (Filed with Registration Statement No. 333-00505.)
4-L	A copy of the Indenture between DPL and The Chase Manhattan Bank (ultimate successor to Manufacturers Hanover Trust Company), as Trustee, dated as of November 1, 1988. (Filed with Registration Statement No. 33-46892.)
4-M	A copy of the Indenture (for Unsecured Subordinated Debt Securities relating to Trust Securities) between DPL and Wilmington Trust Company, as Trustee, dated as of October 1, 1996. (Filed with Registration Statement No. 333-20715.)
4-N	A copy of the Officer's Certificate dated October 3, 1996, establishing the 8.125% Junior Subordinated Debentures, Series I, Due 2036. (Filed with Registration Statement No. 333-20715.)
4-O	A copy of the Guarantee Agreement between DPL, as Guarantor, and Wilmington Trust Company, as Trustee, dated as of October 1, 1996. (Filed with Registration Statement No. 333-20715.)
4-P	A copy of the Amended and Restated Trust Agreement between DPL, as Depositor, and Wilmington Trust Company, Barbara S. Graham, Edric R. Mason and Donald P. Connelly, as Trustees, dated as of October 1, 1996. (Filed with Registration Statement No. 333-20715.)
4-Q	A copy of the Agreement as to Expenses and Liabilities dated as of October 1, 1996, between DPL and Delmarva Power Financing I. (Filed with Registration Statement No. 333-20715.)
10-A	Copy of the Supplemental Executive Retirement Plan, revised as of October 29, 1991. (Filed with Form 10-K for the year ended December 31, 1992, File No. 1-1405.)

Exhibit Number	
10-B	Copies of amendments to the Supplemental Executive Retirement Plan, effective June 15, 1994, and November 1, 1994. (Filed with Form 10-K for the year ended December 31, 1994, File No. 1-1405.)
10-C	Copy of the Long Term Incentive Plan amended and restated as of January 1, 1996. (Filed with Form 10-K for the year ended December 31, 1996, File No. 1-1405.)
10-D	Copies of amendments to the Long Term Incentive Plan, effective January 1, 1997, and January 30, 1997. (Filed with Form 10-K for the year ended December 31, 1996, File No. 1-1405.)
10-E	Copy of the severance agreement with members of management. (Filed with Form 10-K for the year ended December 31, 1994, File No. 1-1405.)
10-F	Copy of the current listing of members of management who have signed the severance agreement. (Filed with Form 10-K for the year ended December 31, 1996, File No. 1-1405.)
10-G	Copy of the Management Life Insurance Plan amended and restated as of January 1, 1992. (Filed with Form 10-K for the year ended December 31, 1996, File No. 1-1405.)
10-H	Copy of the Deferred Compensation Plan, effective as of January 1, 1996. (Filed with the Form 10-K for the year ended December 31, 1995, File No. 1-1405.)
12-A	Computation of ratio of earnings to fixed charges.
12-B	Computation of ratio of earnings to fixed charges and preferred dividends.
23	Consent of Independent Accountants.
27	Financial Data Schedule.

(b) No Reports on Form 8-K were filed during the fourth quarter of 1998.

On January 26, 1999, DPL filed a Report on Form 8-K under Item 5, Other Events, concerning proposed legislation in Delaware to restructure the electric utility industry.

DELMARVA POWER & LIGHT COMPANY

SCHEDULE OF OPERATING STATISTICS
FOR THE THREE YEARS ENDED DECEMBER 31, 1998

The table below sets forth selected financial and operating statistics for DPL's electric and gas businesses for the three years ended December 31, 1998.

	1998	1997	1996
ELECTRIC:			
Electricity generated and purchased (MWH):			
Generated	9,657,472	9,067,236	10,307,299
Purchased	6,510,738	5,908,796	6,195,720
Interchange deliveries	(1,968,200)	(1,078,471)	(2,855,109)
Total system output for load	14,200,010	13,897,561	13,647,910
Nonregulated purchases	7,324,399	4,201,619	—
Total output	21,524,409	18,099,180	13,647,910
Electric sales (MWH):			
Residential	4,183,854	4,097,773	4,262,710
Commercial	4,288,876	4,091,636	4,018,120
Industrial	3,645,901	3,598,006	3,331,175
Resale	1,236,489	1,335,226	1,333,268
Other sales (1)	73,983	109,124	(19,557)
Total service territory sales	13,429,103	13,231,765	12,925,716
Merchant sales (2)	7,713,418	4,201,619	—
Total sales excluding interchange	21,142,521	17,433,384	12,925,716
Losses and miscellaneous system uses	381,888	665,796	722,194
Total disposition of energy	21,524,409	18,099,180	13,647,910
Operating revenue (thousands):			
Residential	$ 378,515	$ 377,528	$ 378,520
Commercial	304,477	299,649	286,438
Industrial	169,174	173,413	156,329
Resale	67,104	68,315	65,989
Miscellaneous revenues (3)	36,478	34,451	24,344
Total service territory	955,748	953,356	911,620
Interchange deliveries	99,182	36,430	75,301
Merchant revenues (2)	274,463	102,358	—
Total revenues	$ 1,329,393	$ 1,092,144	$ 986,921
Number of customers (end of period):			
Residential	402,536	396,798	391,611
Commercial	51,454	50,216	49,165
Industrial	657	672	683
Resale	12	12	12
Other	647	624	645
Total customers (4)	455,306	448,322	442,116

(Table continued on next page)

DELMARVA POWER & LIGHT COMPANY

SCHEDULE OF OPERATING STATISTICS—(Continued)
FOR THE THREE YEARS ENDED DECEMBER 31, 1998

	1998	1997	1996
GAS:			
Gas sales and gas transported (Mcf):			
Residential	6,812	7,844	8,692
Commercial	4,705	5,313	5,724
Industrial	2,751	2,772	2,696
Interruptible, transportation and other	7,319	6,926	5,312
Total service territory	21,587	22,855	22,424
Merchant sales	156,741	27,216	1,733
Total	178,328	50,071	24,157
Operating revenue (thousands):			
Residential	$ 57,809	$ 63,937	$ 60,017
Commercial	31,954	34,895	32,191
Industrial	11,311	12,582	12,349
Interruptible, transportation and other	6,113	5,776	5,085
Total service territory	107,187	117,190	109,642
Merchant revenues	427,895	86,867	4,642
Total	$535,082	$204,057	$114,284
Number of customers (end of period):			
Residential	97,558	95,295	93,149
Commercial	7,975	7,793	7,615
Industrial	123	128	139
Interruptible, transportation and other	—	—	1
Total customers (4)	105,656	103,216	100,904

(1) Includes unbilled sales.
(2) Offsystem, competitive sales and other services.
(3) Includes unbilled revenues and other miscellaneous revenues.
(4) Service territory only.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934 the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 26, 1999.

DELMARVA POWER & LIGHT COMPANY
(REGISTRANT)

By: /s/ JOHN C. VAN RODEN
(John C. van Roden, Senior Vice President and Chief Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated, on March 26, 1999.

Signature	Title
/s/ HOWARD E. COSGROVE *(Howard E. Cosgrove)*	Chairman of the Board and Chief Executive Officer
/s/ JOHN C. VAN RODEN *(John C. van Roden)*	Senior Vice President and Chief Financial Officer
/s/ JAMES P. LAVIN *(James P. Lavin)*	Controller and Chief Accounting Officer
/s/ MEREDITH I. HARLACHER, JR. *(Meredith I. Harlacher, Jr.)*	Director
/s/ THOMAS S. SHAW *(Thomas S. Shaw)*	Director
/s/ BARRY R. ELSON *(Barry R. Elson)*	Director
/s/ BARBARA S. GRAHAM *(Barbara S. Graham)*	Director
/s/ AUDREY K. DOBERSTEIN *(Audrey K. Doberstein)*	Director
/s/ JERROLD L. JACOBS *(Jerrold L. Jacobs)*	Director

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

FORM 10-K

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

For the fiscal year ended December 31, 1998

OR

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

Commission file number 1-3559

ATLANTIC CITY ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

New Jersey	**21-0398280**
(State of Incorporation)	(I.R.S. Employer Identification No.)

800 King Street, P.O. Box 231
Wilmington, Delaware 19899
(Address of principal executive offices)

Registrant's telephone number (302) 429-3114

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

Title of each class	**Name of each exchange on which registered**
8.25% Cumulative Quarterly Income Preferred Securities, liquidation preference $25 per preferred security issued by Atlantic Capital I	New York Stock Exchange
7⅜% Cumulative Trust Preferred Capital Securities, liquidation preference $25 per preferred security issued by Atlantic Capital II	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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

All 18,320,937 issued and outstanding shares of Atlantic City Electric Company common stock, $3 per share par value, are owned by Conectiv.

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GLOSSARY

The following glossary lists the abbreviations used in this report.

Term	Definition
7⅜% Debentures	7⅜% Junior Subordinated Debentures
8.25% Debentures	8.25% Junior Subordinated Deferrable Interest Debentures
1992 Energy Act	National Energy Policy Act of 1992
ACE	Atlantic City Electric Company
the Act	The Electric Discount and Energy Competition Act
AFUDC	Allowance For Funds Used During Construction
Atlantic	Atlantic Energy, Inc.
ALJ	Administrative Law Judge
BGS	Basic Generation Service
Clean Water Act	Federal Water Pollution Control Act
CRP	Conectiv Resource Partners, Inc.
D&D Fund	Decontamination & Decommissioning Fund
DOE	United States Department of Energy
DPL	Delmarva Power & Light Company
DSM	Demand Side Management Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
Hope Creek	Hope Creek Nuclear Generating Station
IPP	Independent Power Producer
kWh	Kilowatt-hour
LEC	Levelized Energy Clause
Litigation Reform Act	The Private Securities Litigation Reform Act of 1995
LLRW	Low Level Radioactive Waste
LMP	Locational Marginal Pricing
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Merger	A series of merger transactions by which DPL and ACE became subsidiaries of Conectiv
Mortgage	Mortgage and Deed of Trust
MW	Megawatt
NERC	North American Electric Reliability Council
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
NJPDES	New Jersey Pollution Discharge Elimination System
NOTR	Northeast Ozone Transport Region
NO_x	Oxides of Nitrogen
NPDES	National Pollution Discharge Elimination System
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
Peach Bottom	Peach Bottom Atomic Power Station
PECO	PECO Energy Company
PJM Interconnection	Pennsylvania-New Jersey-Maryland Interconnection Association
PSE&G	Public Service Electric and Gas Company
PUHCA	Public Utility Holding Company Act of 1935

Term	Definition
PURPA	Public Utility Regulatory Policy Act of 1978
RACT	Reasonably Available Control Technology
RISC	Rate Intervention Steering Committee
RTP	Real Time Pricing
Salem	Salem Nuclear Generating Station
SALP	Systematic Assessment of Licensee Performance
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS No. 71	SFAS No. 71, "Accounting For the Effects of Certain Types of Regulation"
SFAS No. 88	SFAS No. 88, "Employers' Accounting For Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits"
SFAS No. 128	SFAS No. 128, "Earnings Per Share"
SFAS No. 131	SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information"
SFAS No. 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SO_2	Sulfur Dioxide
TEFA	Transitional Energy Facility Assessment Tax
USEPA	United States Environmental Protection Agency
VRDB	Variable Rate Demand Bonds
Westinghouse	Westinghouse Electric Corporation

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PART I

Item 1. Business

General

Atlantic City Electric Company (ACE) is a regulated public electric utility and a subsidiary of Conectiv, which is a Delaware corporation and a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). ACE was organized under the laws of New Jersey on April 28, 1924 by merger and consolidation of several utility companies. ACE holds the franchises necessary to provide regulated electric service in its service territory.

ACE is primarily engaged in generating, purchasing, delivering, and selling electricity. ACE serves approximately 488,800 customers in its service territory which covers an area of about 2,700 square miles in the southern one-third of New Jersey and has a population of approximately 850,000. ACE's customer base is comprised primarily of residential and commercial customers. In 1998, the percentages of retail electric revenues contributed by customer class were as follows: residential—47.3%; commercial—41.1%; and industrial / other—11.6%.

ACE's utility business is subject to regulation with respect to its retail electric sales by the New Jersey Board of Public Utilities (NJBPU). The Federal Energy Regulatory Commission (FERC) also has regulatory authority over certain aspects of ACE's electric utility business, including the transmission of electricity, the sale of electricity to municipalities and electric cooperatives, and interchange and other purchases and sales of electricity involving other utilities. ACE is also subject to regulation by the Pennsylvania Public Utility Commission in limited respects concerning property and operations in Pennsylvania.

On March 1, 1998, ACE and Delmarva Power & Light Company (DPL) became wholly-owned subsidiaries of Conectiv (the Merger). Before the Merger, ACE was owned by Atlantic Energy, Inc. (Atlantic). As a result of the Merger, Atlantic no longer exists and Conectiv owns, directly or indirectly, ACE, DPL and the nonutility subsidiaries formerly held separately by Atlantic and DPL. Conectiv is a registered holding company under PUHCA, which imposes certain restrictions on the operations of registered holding companies and their subsidiaries.

As of December 31, 1998, ACE had 857 employees, of which 524 were represented by a collective bargaining labor organization. During 1998, ACE reduced its workforce by 573 employees, including 354 employees separated through Merger-related employee separation programs and 219 employees transferred to Conectiv Resource Partners, Inc. (CRP), a Conectiv subsidiary and service company established pursuant to PUHCA. CRP provides a variety of support services to Conectiv subsidiaries, and its employees are primarily former DPL and ACE employees. The costs of CRP are directly assigned, distributed and allocated to the Conectiv subsidiaries using CRP's services, including ACE.

For additional information about the Merger, refer to Note 4 to ACE's 1998 Consolidated Financial Statements included in Item 8 of Part II.

For information concerning ACE's business segments, refer to Note 18 to ACE's 1998 Consolidated Financial Statements included in Item 8 of Part II.

Competition and Electric Utility Industry Restructuring

For information concerning restructuring the electric utility industry in New Jersey and the Electric Discount and Competition Act (the Act), see Note 5 to ACE's 1998 Consolidated Financial Statements included in Item 8 of Part II. Under the Act, New Jersey electric customers may choose an electricity supplier beginning August 1, 1999. Customers will continue to pay the local utility a regulated price for delivery of electricity over the transmission and distribution system. As electric utility industry restructuring is implemented in ACE's and other utilities' service territories, gross margins earned from supplying electricity are expected to decrease as

competition to supply customers with electricity increases. As a greater percentage of ACE's revenues become subject to competition, financial risks and rewards, and the volatility of earnings are expected to increase. ACE's ability to continue reducing costs by streamlining operations, regulatory decisions pursuant to restructuring under the Act, retention of existing customers and the ability to gain new customers are significant determinants of ACE's future success.

Installed Capacity

The megawatts (MW) of net installed summer electric generating capacity available to ACE to serve its peak load as of December 31, 1998, are presented below. See Item 2, Properties, for additional information.

Source of Capacity	MW	% of Total
Coal-fired generating units	471	19
Oil-fired generating units	295	12
Combustion turbines/combined cycle generating units	524	21
Nuclear generating units	380	15
Diesel units	9	—
Long-term purchased capacity	828	33
Subtotal	2,507	100
Short-term purchased capacity	9	—
Total	2,516	100

The net generating capacity available for operations at any time may be less than the total net installed generating capacity due to generating units being out of service for inspection, maintenance, repairs, or unforeseen circumstances.

As restructuring of the electric utility industry is implemented, ACE expects to sell some of its generating units. ACE has identified certain generating assets that may be sold, but has not determined when such sale, or sales, would occur.

Electricity Supply

As a member of the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM Interconnection), ACE is obligated to maintain capacity levels based on its allocated share of estimated aggregate PJM Interconnection capacity requirements. (The PJM Interconnection is discussed on page I-3.) ACE periodically updates its forecast of peak demand and PJM Interconnection reserve requirements, and re-evaluates resources available to supply projected growth. Any short-term capacity deficiencies related to obligations to the PJM Interconnection are expected to be satisfied through short-term capacity-only purchases. Incremental energy supply needs are expected to be filled through purchased power.

ACE experienced it highest historical peak demand of 2,162 MW on July 22, 1998, which was 1.6% above the previous peak demand of 2,127 MW recorded on August 16, 1997. ACE's capacity obligation to the PJM Interconnection, which includes a reserve margin, is based on normal weather conditions and full implementation of its demand-side management programs. Under these conditions, ACE's 1998 peak demand would have been approximately 2,115 MW. ACE's installed capacity of 2,501 MW at the time of the peak resulted in a reserve margin of 18%, computed under PJM Interconnection guidelines. ACE's reserve obligation to the PJM Interconnection is approximately 20%.

The sources of the electricity supplied to ACE's customers during 1998, 1997, and 1996 are shown below:

Source of Electricity	1998	1997	1996
Generation fuel type			
Coal	26%	26%	28%
Nuclear	29	18	15
Oil/Natural Gas	4	3	2
Interchange and Purchased Power	12	30	35
Nonutility Purchased Power	29	23	20
Total	100%	100%	100%

Pennsylvania-New Jersey-Maryland Interconnection Association

As a member of the PJM Interconnection, ACE's generation and transmission facilities are operated on an integrated basis with other electricity suppliers in Pennsylvania, New Jersey, Maryland, and the District of Columbia, and are interconnected with other major utilities in the United States. This power pool improves the reliability and operating economies of the systems in the group and provides capital economies by permitting shared reserve requirements. The PJM Interconnection's installed capacity as of December 31, 1998, was 57,551 MW. The PJM Interconnection peak's demand during 1998 was 48,663 MW on August 15, which resulted in a summer reserve margin of 18.2% (based on installed capacity of 57,511 MW on that date).

On October 15, 1998, the PJM Interconnection began operating a centralized capacity credit market, providing a new option to participants for procuring and selling surplus capacity to meet reliability obligations within the PJM Interconnection region. Capacity is the capability to produce electric power, typically from owned generation or third-party purchase contracts and differs from the electric energy markets, which trade the actual energy being generated. This market facilitates the selling and buying of capacity for participants by providing a single point of contact for market participants and a published capacity market clearing price.

Effective April 1, 1998, the PJM Interconnection implemented locational marginal pricing (LMP) to establish the market clearing prices for electric energy and to price electric transmission usage based upon costs associated with transmission system congestion. When there is no congestion on the power system and energy is flowing on the grid in an unconstrained manner, energy prices are cleared at the highest bid accepted by the PJM Interconnection for the entire PJM Interconnection region. When a limit is reached on the transmission grid, the PJM Interconnection will operate generators to preserve system reliability. LMP allows the PJM Interconnection to send price signals to raise and lower generator output when the power flows are constrained. Different energy market clearing prices are paid by wholesale power buyers and sellers on the power grid that reflect the value relative to a system constraint. LMP provides for an efficient allocation of congestion costs to transmission users within the PJM Interconnection region. The FERC has approved the use of the LMP congestion management system to allow electric energy market participants with power contracts on neighboring electric systems to compensate the PJM Interconnection for any unintended flows on the PJM Interconnection system, rather than forcing those participants to curtail their contracts.

Currently, the PJM Interconnection Operating Agreement requires bids to sell electricity received from generation located within the PJM Interconnection control area not to exceed the variable cost of producing such electricity. Transactions that are bid into the PJM pool from generation located outside the PJM Interconnection control area are capped at $1,000 per megawatt hour. All power providers are paid the LMP set through power providers' bids. Certain PJM Interconnection members have requested that FERC revise the PJM Interconnection Operating Agreement to allow the submission of market based bids to the PJM Interconnection energy market.

Purchased Power

The Public Utility Regulatory Policy Act of 1978 (PURPA) established a class of nonutility power suppliers, known as independent power producers (IPPs), and required electric utilities to purchase the excess power from IPPs. As a result of PURPA, ACE has long-term contracts with four IPPs for the purchase of 659 MW of capacity and energy. In view of electric utility industry restructuring, various parties continue to seek the repeal of PURPA; however, federal action with regard to PURPA is not likely to affect ACE's IPP contracts.

ACE's NJBPU-approved IPP contracts are shown below.

Project Location	Fuel Type	MW Provided	Date of Commercial Operation
Chester, Pennsylvania	solid waste	75	September 1991
Pedricktown, New Jersey	gas	116	March 1992
Carney's Point, New Jersey	coal	249	March 1994
Logan Township, New Jersey	coal	219	September 1994
Total		659	

ACE is also currently purchasing 125 MW of capacity and energy from PECO Energy Company (PECO) under a contract which ends May 31, 2000. This agreement replaced a terminated agreement with Pennsylvania Power & Light Company, effective March 1998. ACE also contracts with other electric suppliers on an as-needed basis for the purchase of short-term generating capacity, energy and transmission capacity.

Nuclear Power Plants

ACE owns 5% of the 1,031 MW, Hope Creek Nuclear Generating Station (Hope Creek) and 7.41% of the 2,212 MW, Salem Nuclear Generating Station (Salem). The Hope Creek Unit and Salem Units 1 and 2 are located adjacent to each other in Salem County, New Jersey, and are operated by Public Service Electric & Gas (PSE&G). ACE also owns 7.51% of the 2,186 MW, Peach Bottom Atomic Power Station (Peach Bottom), which has Units 2 and 3, is located in York County, Pennsylvania, and is operated by PECO.

ACE's ownership share in nuclear power plants provided approximately 15% of its installed capacity as of December 31, 1998. In 1998, ACE's share of output from the jointly-owned nuclear power plants provided 29% of the electricity used by ACE's customers. See Note 7 to ACE's 1998 Consolidated Financial Statements included in Item 8 of Part II for information about ACE's investment in jointly-owned generating stations.

The operation of nuclear generating units is regulated by the Nuclear Regulatory Commission (NRC). Such regulation requires that all aspects of plant operation be conducted in accordance with NRC safety and environmental requirements and that continuous demonstrations be made to the NRC that plant operations meet applicable requirements. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate.

As a by-product of nuclear operations, nuclear generating units produce low-level radioactive waste (LLRW). LLRW is accumulated on-site until shipped to a federally licensed permanent disposal facility. Salem, Hope Creek, and Peach Bottom have on-site interim storage facilities with five-year storage capacities.

For a discussion of the cycle of production, use and disposal of nuclear fuel, see ''Nuclear'' on page I-6.

For a discussion of ACE's funding of its share of the estimated future cost of decommissioning the Hope Creek, Peach Bottom, and Salem nuclear reactors, see Note 15 to ACE's 1998 Consolidated Financial Statements included in Part II, Item 8.

The NRC is requiring nuclear plant operators to report by July 1, 1999, that their nuclear power plants are Year 2000 ready, or will be Year 2000 ready, by January 1, 2000. PSE&G and PECO have informed ACE that they are on schedule to meet the July 1, 1999 response date and that their nuclear operations' Year 2000 programs will make Salem, Hope Creek, and Peach Bottom Year 2000 ready by January 1, 2000.

Salem Units 1 and 2 were removed from operation by PSE&G in the second quarter of 1995 due to operational problems, and maintenance and safety concerns. Due to degradation of a significant number of tubes in the Unit 1 steam generators, PSE&G replaced the Unit 1 steam generators. After receiving NRC authorization, PSE&G returned Unit 2 to service on August 30, 1997, and Unit 1 to service on April 17, 1998. On July 29, 1998, the NRC removed Salem from its ''watch list'' of troubled nuclear plants. The Salem Unit 2 steam generators will be inspected for tube degradation in upcoming outages.

See Note 13 to ACE's 1998 Consolidated Financial Statements included in Part II, Item 8, for information concerning ACE's lawsuit against Westinghouse Electric Corporation, the designer and manufacturer of the Salem steam generators, and the financial impact of the outages.

Systematic Assessment of Licensee Performance (SALP) reports issued by the NRC rate licensee performance in four assessment areas: Operations, Maintenance, Engineering and Plant Support. Ratings range from a high of "1" to a low of "3." In September 1998, the NRC issued a SALP Report on the performance of activities at Salem for the period March 1, 1997, to August 1, 1998. Salem received a rating of 1 in Operations, a 2 in Maintenance, a 2 in Engineering, and a 1 in Plant Support. The NRC noted that the overall performance at Salem improved, as demonstrated by a nearly event-free return of both units to operation following the extended outage.

On June 8, 1998, the NRC issued a SALP report on Hope Creek for the period November 10, 1996, to May 16, 1998. Hope Creek received a rating of 2 in the areas of Operations, Maintenance, and Engineering, and a rating of 1 in the area of plant support. The NRC noted improved performance in all functional areas during the period.

On July 17, 1997, the NRC issued a SALP report on Peach Bottom for the period October 15, 1995, to June 7, 1997. Peach Bottom received a rating of 1 in the areas of Operations, Maintenance, and Plant Support, and 2 in Engineering.

On September 16, 1998, the NRC announced that it was suspending the SALP report process until it completes a review of its nuclear power plant performance assessment process. The SALP process has not yet been resumed or replaced.

Fuel Supply for Electric Generation

ACE's electric generating capacity by fuel type is shown under "Installed Capacity" on page I-2. To facilitate the purchase of adequate amounts of fuel at reasonable prices, ACE contracts with various suppliers of coal, oil, and natural gas on both a long- and short-term basis. Prices under oil and natural gas contracts are generally determined by market-based indices.

Coal

B.L. England Units 1 and 2, Deepwater Unit 6, and the Keystone and Conemaugh Generating Stations are coal-fired. During 1998, 92% of ACE's coal supply for these units was purchased under two long-term contracts, which expire in April 1999 and June 2001, and the balance was purchased on the spot market. Approximately 56% of ACE's projected coal requirements are expected to be provided under supply contracts. ACE does not anticipate any difficulty in obtaining adequate amounts of coal at reasonable prices.

Oil

Currently, 100% of the residual oil used in B.L. England Unit 3 and Deepwater Unit 1 is supplied under a three-year contract that expires October 31, 2000. Another three-year contract which expires October 31, 2000, provides all of the distillate oil supply for ACE's combustion turbines.

Gas

Natural gas is the primary fuel for six of ACE's combustion turbines and a secondary fuel at Deepwater Units 1 and 6. Natural gas for ACE's gas-fired generating units is purchased primarily from the local gas distribution company on a firm basis and is also purchased from other suppliers, such as marketers, producers, and utilities. The gas is delivered under contract through the interstate pipeline system.

Nuclear

The supply of fuel for nuclear generating units involves the mining and milling of uranium ore to uranium concentrate, conversion of the uranium concentrate to uranium hexaflouride, enrichment of the uranium hexaflouride gas, conversion of the enriched gas to fuel pellets, and fabrication of fuel assemblies. After spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The federal government has an obligation for the transportation and ultimate disposal of the spent fuel, as discussed below.

PSE&G has informed ACE it has several long-term contracts with uranium ore operators, converters, enrichers and fabricators to process uranium ore to uranium concentrate to meet the currently projected requirements for Salem and Hope Creek. ACE has also been advised by PECO that it has similar contracts to satisfy the fuel requirements of Peach Bottom. Currently, there is an adequate supply of nuclear fuel for Salem, Hope Creek, and Peach Bottom.

In conformity with the Nuclear Waste Policy Act of 1982 (NWPA), PSE&G and PECO have entered into contracts with the United States Department of Energy (DOE) on behalf of the joint owners providing that the federal government shall for a fee take title to, transport, and dispose of spent nuclear fuel and high level radioactive waste from the Salem, Hope Creek, and Peach Bottom reactors. In accordance with the NWPA, ACE pays the DOE one-tenth of one cent per kilowatt-hour (kWh) of nuclear generation (net of station use) for the future cost of spent nuclear fuel disposal. Under the NWPA, the DOE was to begin accepting spent fuel for permanent off-site storage no later than January 1998. However, no such repositories are in service or under construction. The DOE has stated that it would not be able to open a permanent, high level nuclear waste storage facility until 2010, at the earliest.

Pursuant to NRC rules, spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in independent spent nuclear fuel storage installations located at or away from reactor sites for at least 30 years beyond the licensed life for operation (which may include the term of a revised or renewed license).

PSE&G has advised ACE that, as a result of reracking the two spent fuel storage pools at Salem, the availability of spent fuel storage capacity is estimated to be adequate through 2012 for Unit 1 and 2016 for Unit 2. PSE&G has also advised ACE that the Hope Creek pool is also fully racked and it is expected to provide adequate storage capacity until 2006. PECO has advised ACE that spent fuel racks at Peach Bottom have storage capacity until 2000 for Unit 2 and until 2001 for Unit 3. PECO has also advised ACE that it is constructing an on-site dry storage facility, which is expected to be operational in 2000, to provide additional storage capacity.

Regulatory Matters

For information concerning restructuring the electric utility industry in New Jersey, see Note 5 to ACE's 1998 Consolidated Financial Statements included in Item 8 of Part II.

Electric Retail Rates

ACE's base rates for retail electric service are subject to the approval of the NJBPU. However, the utility ratemaking process is changing in New Jersey, as discussed in Note 5 to ACE's 1998 Consolidated Financial Statements included in Item 8 of Part II.

For information concerning base rate increases and decreases affecting the 1996-1998 results of operations, including the Merger-related base rate decrease and base rate decreases expected in connection with the electric utility industry restructuring, see Notes 3, 5 and 13 to ACE's 1998 Consolidated Financial Statements included in Item 8 of Part II.

Off-Tariff Rates

Legislation enacted in New Jersey in July 1995 allows the NJBPU, upon petition from any electric or gas utility, to adopt a plan of regulation other than the traditional rate-base/rate-of-return regulation. In addition, on a case-by-case basis, the law allows utilities to petition the NJBPU for the right to offer customers, who meet certain conditions, off-tariff, discounted rates. Off-tariff pricing arrangements with certain ACE customers have been arranged. Refer to "Electric Revenues" in ACE's Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) herein for further information regarding off-tariff rates (OTRAs).

Levelized Energy Adjustment Clause

Information concerning the Levelized Energy Adjustment Clause (LEC) is included in the Notes to ACE's 1998 Consolidated Financial Statements (Part II, Item 8) as follows: (i) the operation of the LEC and deferred energy accounting are discussed under "Deferred Energy Costs" in Note 1, (ii) the nuclear performance standard is discussed under "Other Rate Matters" in Note 5, and (iii) the financial impact of extended outages at Salem is discussed in Note 13.

In January 1999, ACE filed with the NJBPU a petition requesting that the estimated cost of oxides of nitrogen (NO_x) allowances in 1999 of $4.8 million be included in LEC rates. A ruling on this matter is expected during 1999. For information concerning NO_x emission regulations, see "Air Quality Regulations" on page I-9.

On April 11, 1997, the Rate Intervention Steering Committee (RISC) submitted its brief on its appeal to the Superior Court of New Jersey in response to the NJBPU's decision which provided for ACE's recovery (through LEC rates) of the cost of power purchased from IPPs. In May 1998, the Superior Court of New Jersey rejected RISC's appeal and upheld the NJBPU's decision providing for LEC recovery of IPP purchased power costs. In May 1998, RISC appealed the Superior Court's decision to the Supreme Court of New Jersey, which denied RISC's appeal in July 1998.

The LEC is expected to be superceded by provisions contained in the Act which permit Basic Generation Service (BGS) suppliers full and timely recovery of their costs. The Act also authorizes the NJBPU to allow the deferral and subsequent recovery of BGS costs if necessary for attainment of the rate reductions required by the Act. Regulations governing BGS are expected to be promulgated by the NJBPU prior to beginning retail choice of electricity suppliers in New Jersey.

Electric Distribution Service Reliability and Quality Standards

On December 30, 1997, the NJBPU directed its Staff to initiate an inquiry into establishing measurable performance and reliability standards for New Jersey electric and gas utilities. The Staff's most recent draft proposal does not propose monetary penalties, but does require establishment of utility specific standards and contains potentially costly and burdensome reporting requirements. The NJBPU is expected to review this matter in 1999.

Other Regulatory Matters

The 1992 Energy Act provided for creation of a Decontamination & Decommissioning (D&D) Fund to pay for the future clean-up of DOE gaseous diffusion enrichment facilities. Domestic utilities and the federal government are required to make payments to the D&D Fund until 2008 or $2.25 billion, adjusted annually for inflation, is collected. The liability accrued for ACE's share of the D&D Fund was $5.7 million as of December 31, 1998. ACE is recovering this cost through LEC revenues.

ACE has cost allocation and direct charging mechanisms in place to ensure that there is no cross-subsidization of its competitive activities by regulated utility activities. In accordance with the NJBPU's order which approved the Merger, ACE filed Conectiv's Cost Accounting Manual and the Service Agreement between ACE and CRP with the NJBPU on October 28, 1998.

Certain types of transactions between ACE and its affiliates may require prior approval of the NJBPU.

The New Jersey Public Utility Fault Determination Act requires the NJBPU to make a determination of fault with regard to any past or future accident at any electric generating or transmission facility, prior to granting a utility's request for a rate increase to cover accident-related costs in excess of $10 million. However, the law allows a utility to file for non-accident related rate increases during such fault determination hearings and to recover contributions to federally mandated or voluntary cost-sharing plans. The law further allows the NJBPU to authorize the recovery of certain fault-related repair, cleanup, replacement power or damage costs, if appropriate.

Capital Spending and Financing Program

For financial information concerning ACE's capital spending and financing program, refer to "Liquidity and Capital Resources" in the MD&A included in Item 7 of Part II and Notes 8 and 9 to ACE's 1998 Consolidated Financial Statements, included in Item 8 of Part II.

ACE's ratios of earnings to fixed charges and earnings to fixed charges and preferred stock dividends under the Securities and Exchange Commission (SEC) Methods for 1994-1998 are shown below.

	Year Ended December 31,				
	1998	1997	1996	1995	1994
Ratio of Earnings to Fixed Charges (SEC Method)	1.66	2.84	2.59	3.19	3.07
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends (SEC Method)	1.55	2.58	2.16	2.43	2.26

Under the SEC Method, earnings, including Allowance For Funds Used During Construction (AFUDC), have been computed by adding income taxes and fixed charges to net income. Fixed charges include gross interest expense, the estimated interest component of rentals, and dividends on preferred securities of subsidiary trusts. For the ratio of earnings to fixed charges and preferred stock dividends, preferred stock dividends represent annualized preferred stock dividend requirements multiplied by the ratio that pre-tax income bears to net income. Excluding Merger-related pre-tax charges of $79.1 million in 1998 and $22.2 million in 1997, the Ratio of Earnings to Fixed Charges was 2.74 in 1998 and 3.15 in 1997, and the Ratio of Earnings to Fixed Charges and Preferred Stock Dividends was 2.55 in 1998 and 2.86 in 1997.

Environmental Matters

ACE is subject to various federal, regional, state, and local environmental regulations, including air and water quality control, oil pollution control, solid and hazardous waste disposal, and limitation on land use. Permits are required for ACE's construction projects and the operation of existing facilities. ACE has incurred, and expects to continue to incur, capital expenditures and operating costs because of environmental considerations and requirements. ACE has a continuing program to assure compliance with the environmental standards adopted by various regulatory authorities.

Included in ACE's forecasted capital requirements are construction expenditures for compliance with environmental regulations, which are estimated to be $2 million in 1999.

Air Quality Regulations

The federal Clean Air Act requires utilities and other industries to significantly reduce emissions of air pollutants such as sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). Title IV of the Clean Air Act, the acid rain provisions, established a two-phase program which mandated reductions of SO_2 and NO_x emissions from certain utility units by 1995 (Phase I) and required other utility units to begin reducing SO_2 and NO_x emissions in the year 2000 (Phase II). Phase I emission reduction requirements have been achieved by the jointly-owned Conemaugh generating station and B.L. England Units 1 and 2. The remainder of ACE's wholly- and jointly-owned fossil-fuel units are required to comply with Phase II emission limits.

ACE's facilities must also comply with Title I of the Clean Air Act, the ozone nonattainment provisions, which require states to promulgate Reasonably Available Control Technology (RACT) regulations for existing sources located within ozone nonattainment areas or within the Northeast Ozone Transport Region (NOTR). In accordance with New Jersey Department of Environmental Protection (NJDEP) regulatory requirements, ACE has submitted and received NJDEP's approval of ACE's RACT compliance plan.

Additional "post RACT" NO_x emission regulations are being pursued by states in the NOTR. In New Jersey, post-RACT NO_x control regulations require attainment of summer seasonal emission reductions of up to 65% below 1990 levels by May 1999 and 90% by 2003 through reduced emissions or the procurement of NO_x emission allowances. ACE anticipates spending approximately $5 to $8 million over the next five years to achieve compliance with post-RACT NO_x regulations.

In addition to the above requirements, the United States Environmental Protection Agency (USEPA) has proposed summer seasonal NO_x controls commensurate with reductions of up to 85% below baseline years by the year 2003 for a 22 state region; including Delaware and New Jersey. Since New Jersey will require a greater percent reduction than EPA, the ACE facilities will most likely achieve compliance with the EPA requirement by 2003.

In July 1997, the USEPA adopted new federal air quality standards for particulate matter and ozone. The new particulate matter standard addressed fine particulate matter. Attainment of the fine particulate matter standard may require reductions in NO_x and SO_2. However, under the time schedule announced by the USEPA, particulate matter non-attainment areas will not be designated until 2002 and control measures to meet this standard will not be identified until 2005.

Water Quality Regulations

The federal Water Pollution Control Act, as amended (the Clean Water Act) provides for the imposition of effluent limitations to regulate the discharge of pollutants, including heat, into the waters of the United States. National Pollution Discharge Elimination System (NPDES) permits issued by state environmental regulatory agencies specify effluent limitations, monitoring requirements, and special conditions with which facilities discharging wastewaters must comply. To ensure that water quality is maintained, permits are issued for a term of five years and are modified as necessary to reflect requirements of new or revised regulations or changes in facility operations.

ACE holds New Jersey Pollution Discharge Elimination System (NJPDES) permits issued by the NJDEP for the Deepwater and B.L. England power stations. The NJDEP has issued a draft revised NJPDES permit for the Deepwater station which is currently under review. The NJPDES permit for the B.L. England station will expire in December 1999. Application for renewal will be submitted, as required, in June 1999.

The Clean Water Act also requires that cooling water intake structures be designed to minimize adverse environmental impact. The USEPA is required by a consent order to propose regulations in 1999 for determining whether cooling water intake structures represent the best technology available for minimizing adverse environmental impacts. Final action on the proposed regulations is required in 2001.

PSE&G is implementing the 1994 NJPDES permit issued for the jointly-owned Salem facility which requires, among other things, water intake screen modifications and wetlands restoration. Under the 1994 permit, PSE&G is continuing to restore wetlands and conduct the requisite management and monitoring associated with the special conditions of the 1994 permit. In 1999, PSE&G must apply to renew Salem's NJPDES permit.

Hazardous Substances

The nature of the electric utility business results in the production, or handling, of various by-products and substances which may contain substances defined as hazardous under federal or state statutes. The disposal of hazardous substances can result in costs to clean up facilities found to be contaminated due to past disposal practices. Federal and state statutes authorize governmental agencies to compel responsible parties to clean up certain abandoned or uncontrolled hazardous waste sites. ACE's exposure is minimized by adherence to environmental standards for ACE-owned facilities and through a waste disposal contractor screening and audit process. ACE has accrued a $1.0 million liability for potential future remediation costs associated with certain hazardous waste sites.

In 1991, the NJDEP identified ACE as one of a number of parties allegedly responsible for the placement of certain hazardous substances in a sanitary landfill in Atlantic County, New Jersey. Pursuant to an action in 1992 by the USEPA, ACE was named as one of several defendants in connection with the alleged release of hazardous substances at a site located in Gloucester County, New Jersey. ACE's cumulative contributions to the remediation and clean-up of these sites have been approximately $0.4 million.

Executive Officers

The names, ages, and positions of all of the executive officers of ACE as of December 31, 1998, are listed below, along with their business experiences during the past five years. Officers are elected annually by Conectiv's Board of Directors. There are no family relationships among these officers, nor any arrangement or understanding between any officer and any other person pursuant to which the officer was selected.

Executive Officers of ACE
(As of December 31, 1998)

Name, Age and Position	Business Experience During Past 5 Years
Howard E. Cosgrove, 55, ... Chairman of the Board and Chief Executive Officer	Elected 1998 as Chairman of the Board and Chief Executive Officer of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Elected 1992 as Chairman of the Board, President and Chief Executive Officer and Director of Delmarva Power & Light Company.
Meredith I. Harlacher, Jr., 56, ... President	Elected 1998 as President and Chief Operating Officer of Conectiv, and President and Chief Operating Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1993 as Senior Vice President of Atlantic Energy, Inc.
Barry R. Elson, 57, ... Executive Vice President	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1997 as Executive Vice President, Delmarva Power & Light Company. Executive Vice President, Cox Communications, Inc., Atlanta, Georgia, from 1995 to 1996. Senior Vice President, Cox Enterprises/Cox Communications, Inc., Atlanta, Georgia, from 1984 to 1995.
Thomas S. Shaw, 51, ... Executive Vice President	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1992 as Senior Vice President, Delmarva Power & Light Company.
Barbara S. Graham, 50, ... Senior Vice President and Chief Financial Officer	Elected 1998 as Senior Vice President and Chief Financial Officer of Conectiv, and Senior Vice President and Chief Financial Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1994 as Senior Vice President, Treasurer and Chief Financial Officer, Delmarva Power & Light Company. Vice President and Chief Financial Officer of Delmarva Power & Light Company from 1992 to 1994.
James P. Lavin, 51 ..... Controller and Chief Accounting Officer	Elected 1998 as Controller of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Elected 1993 as Comptroller, Delmarva Power & Light Company.
John C. van Roden, 49 ..... Senior Vice President and Chief Financial Officer*	Elected 1998 as Senior Vice President and Chief Financial Officer, effective January 1999, of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Principal, Cook and Belier, Inc. in 1998. Senior Vice President/Chief Financial Officer and Vice President/Treasurer, Lukens, Inc. from 1987 to 1998.

* Effective January 1999

Item 2. Properties

Substantially all utility plants and properties of ACE are subject to the lien of the Mortgage under which First Mortgage Bonds are issued.

The following table sets forth the net installed summer electric capacity available to ACE to serve its peak load as of December 31, 1998.

Station	Location	Net Installed Capacity (kilowatts)
Coal-Fired		
B L England	Beesley's Pt., NJ	284,000
Conemaugh	New Florence, PA	65,000 (A)
Keystone	Shelocta, PA	42,000 (A)
Deepwater	Pennsville, NJ	80,000
		471,000
Oil-Fired		
B L England	Beesley's Pt., NJ	155,000
Deepwater	Pennsville, NJ	140,000
		295,000
Combustion Turbines/Combined Cycle		
Cumberland	Millville, NJ	84,000
Sherman Avenue	Vineland, NJ	81,000
Middle	Rio Grande, NJ	77,000
Carll's Corner	Upper Deerfield Twp, NJ	73,000
Cedar	Cedar Run, NJ	68,000
Missouri Avenue	Atlantic City, NJ	60,000
Mickleton	Mickleton, NJ	59,000
Deepwater	Pennsville, NJ	19,000
Salem	Lower Alloways Creek Twp., NJ	3,000 (A)
		524,000
Nuclear		
Peach Bottom	Peach Bottom Twp., PA	164,000 (A)
Salem	Lower Alloways Creek Twp., NJ	164,000 (A)
Hope Creek	Lower Alloways Creek Twp., NJ	52,000 (A)
		380,000
Diesel Units		
B L England	Beesley's Pt., NJ	8,000
Keystone	Shelocta, PA	300 (A)
Conemaugh	New Florence, PA	400 (A)
		8,700
Long-term Capacity Purchases		828,000
Subtotal		2,506,700
Short-term Capacity Purchases		9,500
Total		2,516,200

(A) ACE's portion of jointly-owned plants.

ACE's electric transmission and distribution system includes 1,231 transmission poleline miles of overhead lines, 9,419 distribution poleline miles of overhead lines, and 1,198 distribution cable miles of underground cables.

Under New Jersey law, the State of New Jersey owns in fee simple for the benefit of the public schools all lands now or formerly flowed by the tide up to the mean high-water line, unless it has made a valid conveyance of its interests in such property. In 1981, because of uncertainties raised as to possible claims of State ownership, the New Jersey Constitution was amended to provide that lands formerly tidal-flowed, but which were not then tidal-flowed at any time for a period of 40 years, were not to be subject to State claim unless the State has specifically defined and asserted a claim within one year period ending November 2, 1982. As a result, the State published maps of the eastern (Atlantic) coast of New Jersey depicting claims to portions of many properties, including certain properties owned by ACE. ACE believes it has good title to such properties and will defend its title, or will obtain such grants from the State as may ultimately be required. The cost to acquire any such grants may be covered by title insurance policies. Assuming that all of such State claims were determined adversely to ACE, they would relate to land, which, together with the improvements thereon, would amount to less than 1% of net utility plant. No maps depicting State claims to property owned by ACE on the western (Delaware River) side of New Jersey were published within one year period mandated by the constitutional amendment. Nevertheless, ACE believes it has obtained all necessary grants from the State for its improved properties along the Delaware River.

Item 3. Legal Proceedings

See Note 13 to ACE's 1998 Consolidated Financial Statements included in Part II, Item 8, for information concerning ACE's lawsuit against Westinghouse Electric Corporation, the designer and manufacturer of the Salem steam generators.

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

A special meeting of ACE shareholders was held on October 14, 1998 to approve an amendment to ACE's Charter. Shareholders voted to eliminate paragraph (7)(B)(c) of Article III of the Charter, removing a restriction on the amount of securities representing unsecured indebtedness issuable by ACE. Votes cast on the proposal were as follows:

	Number of Shares			
	Outstanding	For	Against	Abstain
Common Securities:	18,320,937	18,320,937	—	—
Preferred Securities:				
Cumulative Preferred Stock ($100 Par Value)				
4% Series	77,000	59,223	232	150
4.10% Series	72,000	71,496	—	—
4.35% Series	15,000	12,183	—	—
4.35% 2nd Series	36,000	35,672	—	—
4.75% Series	50,000	45,550	—	—
5.00% Series	50,000	46,455	100	—
No Par Preferred Stock				
$7.80 Series	239,500	239,500	—	—

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ATLANTIC CITY ELECTRIC COMPANY

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

All shares of ACE's common stock are owned by Conectiv, its parent company.

ACE is subject to certain limitations on the payment of dividends to Conectiv. Whenever full dividends on preferred stock have been paid for all past periods, ACE may pay dividends on its common stock from funds legally available for such purpose. Until all cumulative dividends have been paid upon all series of preferred stock and until certain required sinking fund redemptions of such preferred stock have been made, no dividend or other distribution may be paid or declared on the common stock of ACE. In addition, as long as any preferred stock is outstanding, ACE may not pay dividends to Conectiv if, after giving effect to such payment or distribution, the capital of ACE represented by its common stock, together with its surplus as then stated on its books of account, shall in the aggregate, be less than the involuntary liquidation value of the then outstanding shares of preferred stock.

ATLANTIC CITY ELECTRIC COMPANY

ITEM 6. SELECTED FINANCIAL DATA

	1998(1)	1997(2)	1996	1995	1994(3)
			(Thousands of Dollars)		
Operating Results and Data					
Operating Revenues	$1,037,613	$1,084,890	$ 989,647	$ 954,783	$ 913,226
Operating Income	$ 108,868	$ 190,052	$ 165,120	$ 194,687	$ 135,660
Net Income	$ 30,276	$ 85,747	$ 75,017	$ 98,752	$ 93,174
Earnings Applicable to Common Stock	$ 29,385	$ 80,926	$ 65,113	$ 84,125	$ 76,458
Capitalization					
Variable Rate Demand Bonds (VRDB)(4)	$ 22,600	$ 22,600	—	—	—
Long-term Debt	791,127	811,144	802,245	802,356	763,289
Preferred Stock of Subsidiaries					
Subject to Mandatory Redemption	118,950	103,950	113,950	114,750	149,250
Not Subject to Mandatory Redemption	6,231	30,000	30,000	40,000	40,000
Common Stockholder's Equity	730,093	783,033	778,425	796,042	796,260
Total Capitalization with VRDB	$1,669,001	$1,750,727	$1,724,620	$1,753,148	$1,748,799
Other Information					
Total Assets	$2,367,222	$2,436,755	$2,460,741	$2,459,104	$2,418,784
Long-term Capital Lease Obligations	$ 19,523	$ 24,077	$ 24,212	$ 25,277	$ 26,102
Capital Expenditures	$ 71,342	$ 80,896	$ 88,914	$ 100,904	$ 119,961
Common Dividends Declared(5)	$ 81,450	$ 80,857	$ 82,163	$ 81,239	$ 83,482

(1) As discussed in Note 4 to ACE's 1998 Consolidated Financial Statements, in 1998, employee separation and other Merger-related charges reduced operating income $79.1 million and net income $47.2 million.

(2) In 1997, employee separation and other Merger-related charges reduced operating income $22.6 million and net income $15.6 million.

(3) In 1994, employee separation programs reduced operating income $26.6 million and net income $17.3 million.

(4) Although Variable Rate Demand Bonds are classified as current liabilities, ACE intends to use the bonds as a source of long-term financing as discussed in Note 9 to ACE's 1998 Consolidated Financial Statements.

(5) Amounts shown as total, rather than on a per-share basis, since ACE is a wholly-owned subsidiary of Conectiv.

ATLANTIC CITY ELECTRIC COMPANY

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Merger

On March 1, 1998, Atlantic City Electric Company (ACE) and Delmarva Power & Light Company (DPL) became wholly-owned subsidiaries of Conectiv (the Merger). Before the Merger, Atlantic Energy, Inc. (Atlantic) owned ACE and nonutility subsidiaries. As a result of the Merger, Atlantic no longer exists and Conectiv owns (directly or indirectly) ACE, DPL and the nonutility subsidiaries formerly held separately by Atlantic and DPL. Conectiv is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA).

In 1998, enhanced retirement offers and other employee separation programs were utilized to reduce the workforce by 354 positions. The employee separation programs and other Merger-related costs resulted in a $61.1 million pre-tax charge to expense (or $36.6 million after taxes) in 1998 and a $22.2 million pre-tax charge to expenses (or $15.6 million after taxes) in 1997.

Certain of ACE's operational and administrative facilities are being sold due to consolidation of ACE's and DPL's facilities pursuant to the Merger. The estimated fair market value of the assets held for sale is $18.0 million less than their aggregate carrying value of $32.7 million at December 31, 1998. In accordance with Statement of Financial Accounting Standards (SFAS) No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," ACE has recorded an estimated impairment loss of $18.0 million ($10.6 million net of taxes).

Earnings Results Summary

ACE's earnings applicable to common stock were $29.4 million for 1998, compared to $80.9 million for 1997, a $51.5 million decrease. Excluding the Merger-related charges discussed above, ACE earned $76.6 million in 1998 compared to $96.5 million in 1997. This $19.9 million earnings decrease was primarily attributed to higher operations and maintenance expenses.

Excluding the Merger-related charge of $15.6 million in 1997, earnings increased to $96.5 million in 1997 from $65.1 million in 1996. The $31.4 million earnings increase was due to lower operations and maintenance expenses and higher electric revenues, net of fuel, energy and capacity costs. In 1997, ACE's share of operations and maintenance expenses associated with an extended outage at Salem Nuclear Generating Station (Salem) was limited by an agreement which settled ACE's related suit against the Salem operator, Public Service Electric & Gas (PSE&G).

Electric Utility Industry Restructuring

As discussed below, the electric utility industry is being deregulated in New Jersey. Generally, the restructuring will deregulate the supply component of the price charged to a customer for electricity, and electricity suppliers will compete to supply electricity to customers. Customers will continue to pay the local utility a regulated price for the delivery of the electricity over the transmission and distribution system.

Stranded costs are costs which may not be recoverable in a competitive energy supply market due to lower prices or customers choosing a different supplier. Stranded costs generally include above-market costs associated with generation facilities or long-term purchased power agreements, and regulatory assets. ACE has quantified stranded costs in a New Jersey regulatory filing and has proposed a plan seeking approval for recovery of those costs from customers during the transition to a competitive market.

When the New Jersey Board of Public Utilities (NJBPU) issues an order specifically addressing deregulation in ACE's service territory, ACE will cease applying SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," to its electricity supply business. To the extent that the NJBPU's order provides for recovery of

stranded costs through cash flows from the regulated transmission and distribution business, the stranded costs would continue to be recognized as assets under SFAS No. 71. Any stranded costs (including regulatory assets) for which cost recovery is not provided would be expensed.

The amount of stranded costs ultimately recovered from utility customers, if any, and the full impact of New Jersey legislation deregulating the electric utility industry, as discussed below, cannot be predicted. Also, the quantification of stranded costs under existing generally accepted accounting principles (GAAP) differs from methods used in regulatory filings. Among other differences, GAAP precludes recognition of the gains on plants (or purchased power contracts) not impaired, but requires write down of the plants that are impaired. Due to these considerations, market conditions, timing and other factors, ACE's management currently cannot predict the ultimate effects that electric utility industry deregulation may have on the financial statements of ACE, although deregulation may have a material adverse effect on ACE's results of operations.

New Jersey Legislation

The ''Electric Discount and Energy Competition Act'' (the Act) was signed into law by the Governor of New Jersey on February 9, 1999. The Act provides for retail choice of electricity suppliers; deregulation of electric rates and other competitive services, such as metering and billing; separation of competitive and regulated services; unbundling of rates for electric service; and licensing of electric and gas suppliers. August 1, 1999 is the effective starting date for each utility to provide retail choice of electricity suppliers to all of its customers.

The Act requires each electric utility to reduce its rates by at least 5% at the start of retail choice and by 10% within 36 months of the start of choice. If the NJBPU determines that a rate decrease of more than 10% is warranted, a ''just and reasonable'' financial test is applied. The mandated rate reductions must be sustained through the end of the 48th month after choice begins. The Act requires that the rate reductions be measured against the rates in effect on April 30, 1997. The rate reductions mandated by the Act could have a material adverse effect upon the results of operations of ACE.

In connection with the deregulation of electric rates, the Act authorizes the NJBPU to permit electric public utilities to recover the full amount of their stranded costs through a non-bypassable market transition charge, as long as the mandated rate reductions are achieved. The NJBPU will determine the utility's stranded cost amount. The NJBPU-determined stranded cost amount will be subject to periodic recalculation and true-up over the recovery period. The Act establishes an 8-year recovery period for stranded costs associated with owned generation. The recovery period can be extended by the NJBPU so as to allow for the full recovery of the stranded costs and the meeting of mandated rate reductions. The recovery period for stranded costs associated with purchased power contracts is to be the remainder of the contract term. In addition, the Act would allow for the issuance of transition bonds to finance portions of a given utility's stranded costs, as determined to be appropriate by the NJBPU. All savings generated through the use of such transition bonds are to be provided to the customers through rate reductions.

The Act establishes the current incumbent utility as the provider of ''default service'' or Basic Generation Service (BGS) for a period of 3 years. Future proceedings will be held to determine if the provision of BGS should be made competitive. The Act contains numerous provisions regarding the providing of competitive services by each utility. The primary focus is to ensure that there is no cross subsidization from the utility to competitive entities. The NJBPU also is required to develop fair competition standards and conduct an audit to determine that the utilities are in compliance with those standards. The Act gives the NJBPU the authority to order a utility to divest its generating assets if it is determined through a hearing that competition or customers are being adversely affected by plant location, market power or non-competitive rates. The NJBPU may require that the generation function be separated from a utility's non-competitive functions.

The NJBPU is authorized to establish standards for the licensing of energy suppliers, standards for switching customers from one supplier to another, and standards for issues such as credit and collections. The Act also contains provisions for protecting workers displaced by the impacts of the restructuring of the utility industry.

Stranded Cost Filing

Electric utilities in New Jersey, including ACE, previously filed stranded cost estimates and unbundled rates, as required by the NJBPU. On August 19, 1998, an Administrative Law Judge (ALJ) from the New Jersey Office of Administrative Law issued an initial decision on ACE's stranded costs and unbundled rate filing. The ALJ, in reviewing ACE's filing, recognized that ACE's stranded costs were $812 million for nonutility generation contracts and $397 million for owned generation. The ALJ made no specific recommendations on rate issues. A final NJBPU decision on this filing is expected by mid-1999.

Price Regulation of Energy Revenues

Through 1998, customer rates for non-energy costs have been established in past base rate proceedings before the NJBPU. Changes in non-energy (or base rate) revenues due to volume, or rate changes, generally affect the earnings of ACE. Energy costs, including fuel and purchased energy, are currently billed to ACE's rate-regulated customers under ACE's Levelized Energy Clause (LEC) rates. These energy rates are adjusted annually for cost changes and are subject to review by the NJBPU. "Energy revenues," or energy costs billed to customers, do not generally affect net income, because the amount of under- or over-recovered energy costs is generally deferred until it is subsequently recovered from or returned to ACE's rate-regulated customers.

The LEC is expected to be superceded by provisions contained in the Act which permit BGS suppliers full and timely recovery of their costs. The Act also authorizes the NJBPU to permit deferral and subsequent recovery of BGS costs if necessary for attainment of the rate reductions required by the Act. Regulations governing BGS are expected to be promulgated by the NJBPU prior to beginning retail choice of electricity suppliers in New Jersey.

Electric revenues also include interchange delivery revenues, which result primarily from the sale of electricity to other electricity suppliers in the Pennsylvania-New Jersey-Maryland Interconnection, which is an electric power pool. Interchange delivery revenues are currently reflected in the calculation of rates charged to customers under the LEC and, thus, do not affect net income.

Revenues are also earned from sales not subject to price regulation. These sales include off-system bulk commodity sales and retail energy sales.

Electric Revenues

In 1998, the percentage of electric retail revenues contributed by the various retail customer classes were as follows: residential 47.3%; commercial 41.1%; industrial 11.0%; and other 0.6%.

Details of the changes in the various components of electric revenues, from prior years, are shown below.

(dollars in millions)	1998 Variance	1997 Variance
Non-energy (base rate) revenues:		
Change in New Jersey tax law	$(54.1)	$ —
Merger-related base rate decrease	(13.3)	—
Other postretirement benefits (OPEB) costs base rate increase	5.0	—
All other variances	1.3	4.9
Subtotal	(61.1)	4.9
Energy revenues	22.4	13.0
Interchange revenues	45.5	(3.9)
Revenues not subject to price regulation	(40.4)	70.2
Total	$(33.6)	$84.2

The $54.1 million decrease in electric revenues which was due to changes in the New Jersey tax law related to sales of electricity did not affect earnings due to corresponding reductions in taxes other than income taxes. Sales and use taxes billed to customers in 1998 are recorded as a current liability, whereas in prior years, certain other state taxes (which were replaced, in part, by the sales and use taxes) were recorded as revenues. The $13.3 million Merger-related base rate decrease shown above resulted from sharing with utility customers the expected Merger-related cost savings, as discussed under "Other Rate Matters" in Note 5 to the Consolidated Financial Statements. The $5.0 million base rate increase for OPEB is for recovery of the non-cash portion of OPEB costs deferred during 1993-1997.

"All other variances" in electric non-energy revenues primarily reflect growth in retail kilowatt-hour (kWh) sales and the number of customers. Total retail kWh sales increased 3.4% in 1998. Sales growth in 1998 was particularly strong in the commercial and industrial sectors, with increases of 5.3% and 4.4%, respectively. Lower "other electric revenues" in 1998 partly offset the additional revenues from sales growth. Other electric revenues are primarily from non-regulated energy-related activities, such as, indoor and outdoor lighting programs, appliance warranty programs and other energy services, which are now being conducted through other Conectiv subsidiaries.

The 1997 increase for "All other variances" primarily reflects a 1996 $13.0 million refund to customers, which resulted from a stipulation agreement related to Salem (as discussed in Note 13 to the Consolidated Financial Statements), which was substantially offset by ACE's NJBPU-approved Off-Tariff Rate Adjustments (OTRAs). OTRAs are special reduced rates offered by ACE to large customers, which aggregated $10.5 million for 1997.

As discussed under "Price Regulation of Energy Revenues," energy and interchange delivery revenues generally do not affect net income.

Revenues not subject to price regulation decreased $40.4 million in 1998 because non-price regulated bulk power sales have been conducted solely through DPL subsequent to the Merger in order to achieve synergies. In 1997, revenues from non-price regulated sales increased $70.2 million because ACE entered the bulk power market in late-1996 and expanded sales during 1997. The margin provided by the wholesale market revenues in excess of the related energy costs is relatively small due to the competitive nature of bulk power sales.

Other Services Revenues

Other services revenues represent non-regulated energy related services, including energy management services. Effective with the Merger, most of these services are being provided by other Conectiv subsidiaries.

Operation and Maintenance Expenses

Operation and maintenance expenses increased $29.1 million for 1998. An actuarial valuation of ACE's pension plan liability based on updated assumptions and data resulted in a $5.9 million pension expense increase; the remaining increase in operation and maintenance expenses was due primarily to lower capitalized expenses and increased contracted services.

In 1997, operation and maintenance expenses decreased $27.7 million primarily due to reduced Salem outage expenses. An agreement which settled ACE's lawsuit against PSE&G limited ACE's 1997 share of Salem's operation and maintenance expenses.

Depreciation Expense

In 1998, ACE began amortizing OPEB costs deferred during 1993-1997 and depreciating new assets, including business, financial, and human resource management systems. Primarily due to these factors, depreciation expense increased $12.3 million in 1998.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $65.2 million for 1998 due primarily to the changes in the New Jersey tax laws which eliminated the state gross receipts and franchise tax. Earnings generally were not affected

by this decrease due to related reductions in electric revenues resulting from the tax law change. See Note 3 to the Consolidated Financial Statements for further details on the tax law change.

Gain on Preferred Stock Redemption

In October 1998, ACE purchased and retired 237,232 shares, or $23.7 million of various series of mandatorily redeemable preferred stock, which had an average dividend rate of 4.4%. ACE purchased these shares at a discount, which resulted in a gain of $2.5 million that is included in ACE's 1998 results of operations.

Year 2000

The Year 2000 issue is the result of computer programs and embedded systems using a two-digit format, as opposed to four digits, to indicate the year. Computer and embedded systems with this characteristic may be unable to interpret dates during and beyond the year 1999, which could cause a system failure or other computer errors, leading to disruption of operations. A Conectiv project team, originally started in 1996 by ACE, is assisting line management in addressing the issue of computer programs and embedded systems not properly recognizing the Year 2000. A Conectiv corporate officer, reporting directly to the Chief Executive Officer, is coordinating all Year 2000 activities. There are substantial challenges in identifying and correcting the many computer and embedded systems critical to generating and delivering power and providing other services to customers.

The project team is using a phased approach to managing its activities. The first phase is inventory and assessment of all systems, equipment, and processes. Each identified item is given a criticality rating of high, medium or low. Those items rated as high or medium are then subject to the second phase of the project. The second phase is determining and implementing corrective action for the systems, equipment and processes, and concludes with a test of the unit being remediated. The third phase is system testing and compliance certification. Additionally, the project team will be updating existing outage contingency plans to address Year 2000 issues.

Overall, Conectiv's Year 2000 Project covers approximately 140 different systems (some with numerous components) that had been originally identified as high or medium in criticality. However, only 21 of those 140 systems are essential for Conectiv to provide electric and gas service to its customers. The Year 2000 Project team will be focusing on these 21 systems, with additional work on other systems continuing based on their relative importance to Conectiv's business.

The following chart sets forth the current estimated completion percentage of the 140 different systems in the Year 2000 Project by major business group, and for the information technology systems used in managing Conectiv's businesses. Conectiv expects significant progress in remediation and testing over the next quarter based on work that is in process and material that is being ordered.

Business Group	Inventory and Assessment	Corrective Action/Unit Testing	System Testing/ Compliance
Business systems	95%	85%	65%
Power production	95%	30%	30%
Electricity distribution	95%	10%	5%
Gas delivery	95%	60%	60%
Competitive services	90%-95%	30%-80%	30%-80%

ACE is also contacting vendors and service providers to review remediation of their Year 2000 issues. Many aspects of ACE's businesses are dependent on third parties. For example, fuel suppliers must be able to provide coal or gas to allow ACE to generate electricity.

Distribution of electricity is dependent on the overall reliability of the electric grid. ACE is cooperating with the North American Electric Reliability Council (NERC) and the PJM Interconnection in Year 2000 remediation and remediation planning efforts, and has accelerated its Year 2000 Project timeline to be generally in-line with the recommendations of those groups. At this time, a few generating units are scheduled for remediation and

testing in September to coincide with previously scheduled outages. Recent reports issued by the NERC indicate a diminished risk of disruption to the electric grid caused by Year 2000 issues.

Conectiv has incurred approximately $3 million in costs for the Year 2000 Project. Current estimates of the costs for the Year 2000 Project range from $10 million to $15 million. These estimates could change significantly as the Year 2000 Project progresses. The costs set forth above do not include several significant expenditures covering new systems, such as ACE's SAP business, financial and human resources management system and an Energy Control System. While the introduction of these new systems effectively remediated Year 2000 problems in the systems they replaced, ACE has not previously reported the expenditures on these systems in its costs for the Year 2000 Project.

Since the project team is still in the process of assessing and correcting impacted systems, equipment and processes, ACE cannot currently determine whether the Year 2000 issue might cause disruptions to its operations and have impacts on related costs and revenues. ACE assesses the status of the Year 2000 Project on at least a monthly basis to determine the likelihood of business disruptions. Based on its own Year 2000 Project, as well as, reports from NERC and other utilities, ACE's management believes that it is unlikely that significant Year 2000 related disruptions will occur. However, any substantial disruption to ACE's operations could negatively impact ACE's revenues, significantly impact its customers and could generate legal claims against ACE. ACE's results of operations and financial position would likely suffer an adverse impact if other entities, such as suppliers, customers and service providers do not effectively address their Year 2000 issues.

Liquidity and Capital Resources

ACE's principal sources of capital are internally generated funds (net cash provided by operating activities, less common and preferred dividends) and external funds. The principal capital requirements of ACE are construction expenditures, the repayment of debt and capital lease obligations.

Internally generated funds were $157.7 million for 1998, $87.0 million for 1997 and $127.4 million for 1996. The yearly fluctuations in internally generated funds were primarily due to changes in working capital and in fuel revenues, net of energy and capacity costs. Internally generated funds provided 221%, 108%, and 143%, respectively, of the cash required for construction expenditures for 1998, 1997 and 1996. Cash construction expenditures were $71.3 million for 1998, $80.9 million for 1997 and $88.9 million for 1996.

On an interim basis, ACE finances construction costs and other capital requirements in excess of internally generated funds through the issuance of unsecured short-term debt, consisting of commercial paper and notes from banks. As of December 31, 1998, ACE had authority to issue $150 million in short-term debt, all of which was available. ACE also has two separate uncommitted lines of credit in the amount of $25 million and $20 million, respectively. The facilities are renewable annually and bear interest at variable rates.

Common dividends paid to Conectiv in 1998 were $81.5 million. Common dividends paid to Atlantic in 1997 and 1996 were $80.9 million and $82.2 million, respectively.

Presented below are sources and uses of capital from ACE's debt and equity securities.

	1998		1997		1996	
Debt/Equity	Issued	Redeemed	Issued	Redeemed	Issued	Redeemed
			(dollars in millions)			
Short term debt	$ —	$ (72.1)	$ 7.2	$ —	$ 34.4	$ —
Long term debt	85.0	(58.6)	87.6	(74.1)	—	(12.3)
Preferred stock & securities	25.0	(33.8)	—	(20.0)	70.0	(98.9)
	$110.0	$(164.5)	$94.8	$(94.1)	$104.4	$(111.2)

In January 1998, ACE issued $85 million of medium-term notes and used $50 million of the proceeds to redeem medium-term notes, which matured in January 1998.

In May 1998, ACE repaid at maturity $6.0 million of 5.5% Medium-Term Notes and $2.5 million of 7.25% Debentures.

In August 1998, ACE redeemed 100,000 shares of its $8.20 No Par Preferred Stock at $100 per share, or $10.0 million in total (the book value of the preferred stock).

In October 1998, ACE redeemed $23.7 million of preferred stock not subject to mandatory redemption, which had an average dividend rate of 4.4%. In November 1998, a subsidiary trust of ACE issued $25 million of 7 3/8% preferred securities subject to mandatory redemption. On a consolidated basis, Conectiv receives a tax benefit, which is equivalent to the tax effect of a deduction for the trust's distributions on the preferred securities.

The scheduled maturities and sinking fund requirements of debt and preferred securities for the next five years are presented below.

Year	Debt	Preferred Securities	Total
	(Dollars in Thousands)		
1999	$30,075	—	$30,075
2000	$46,075	—	$46,075
2001	$40,075	$11,500	$51,575
2002	$50,075	$11,500	$61,575
2003	$70,075	$ 950	$71,025

ACE's capital structure as of December 31, 1998 and 1997, expressed as a percentage of total capitalization is shown below.

	1998	1997
Long-term debt and variable rate demand bonds	48.8%	47.6%
Preferred securities	7.5%	7.7%
Common stockholder's equity	43.7%	44.7%

ACE's estimated requirements during 1999 for capital expenditures are $85 million. The uncertainty of the impact of electric utility industry restructuring, and the extent to which ACE retains or divest certain of its assets, including generating plants, will affect the ultimate amount of capital expenditures and the amount of external funds required in excess of internally generated funds. ACE's management expects that external funds will be derived from the sale of long-term debt, as required.

Quantitative and Qualitative Disclosures About Market Risks

The following discussion contains "forward looking statements." These projected results have been prepared based upon certain assumptions considered reasonable given the information currently available to ACE. Nevertheless, because of the inherent unpredictability of interest rates and equity market prices as well as other factors, actual results could differ materially from those projected in such forward-looking information.

Interest Rate Risk

ACE is subject to the risk of fluctuating interest rates in the normal course of business. ACE manages interest rates through the use of fixed and, to a lesser extent, variable rate debt. As of December 31, 1998, a hypothetical 10% change in interest rates would not have a material impact on the results of operations of ACE.

Equity Price Risk

ACE maintains trust funds, as required by the Nuclear Regulatory Commission, to fund certain costs of nuclear decommissioning. (See Note 15 to the Consolidated Financial Statements.) These funds are invested primarily in domestic and international equity securities, fixed-rate, fixed income securities, and cash and cash equivalents. By maintaining a portfolio that includes long-term equity investments, ACE is maximizing the returns to be utilized to fund nuclear decommissioning costs. However, the equity securities included in ACE's portfolio are exposed to price fluctuations in equity markets, and the fixed-rate, fixed income securities are exposed to changes in interest rates. ACE actively monitors its portfolio by benchmarking the performance of its investments against certain indexes and by maintaining, and periodically reviewing, established target asset allocation percentages of the assets in the trusts. Because the accounting for nuclear decommissioning recognizes that costs are recovered through electric rates, fluctuations in equity prices and interest rates, while affecting the carrying value of the investments, are offset by the effects of regulation and therefore do not affect earnings.

Commodity Price Risk

Due to the LEC, as discussed under "Price Regulation of Energy Revenues" and in Note 1 to the Consolidated Financial Statements, ACE's exposure to commodity price risk is immaterial to ACE's results of operations.

Forward-Looking Statements

The Private Securities Litigation Reform Act of 1995 (Litigation Reform Act) provides a "safe harbor" for forward looking statements to encourage such disclosure without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been made in this report. Such statements are based on management's beliefs, as well as, assumptions made by and information currently available to management. When used herein, the words "will," "anticipate," "estimate," "expect," "objective," and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following: deregulation and the unbundling of energy supplies and services; an increasingly competitive energy marketplace; sales retention and growth; federal and state regulatory actions; costs of construction; operating restrictions; increased cost and construction delays attributable to environmental regulations; nuclear decommissioning and the availability of reprocessing and storage facilities for spent nuclear fuel; and credit market concerns. ACE undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors pursuant to the Litigation Reform Act should not be construed as exhaustive or as any admission regarding the adequacy of disclosures made by ACE prior to the effective date of the Litigation Reform Act.

ATLANTIC CITY ELECTRIC COMPANY

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF MANAGEMENT

Management is responsible for the information and representations contained in the consolidated financial statements of Atlantic City Electric Company (ACE). Our consolidated financial statements have been prepared in conformity with generally accepted accounting principles, based upon currently available facts and circumstances and management's best estimates and judgments of the expected effects of events and transactions.

ACE and its subsidiary companies maintain a system of internal controls designed to provide reasonable, but not absolute, assurance of the reliability of the financial records and the protection of assets. The internal control system is supported by written administrative policies, a program of internal audits, and procedures to assure the selection and training of qualified personnel.

PricewaterhouseCoopers LLP, independent accountants, are engaged to audit the financial statements and express their opinion thereon. Their audits are conducted in accordance with generally accepted auditing standards which include a review of selected internal controls to determine the nature, timing, and extent of audit tests to be applied.

Conectiv's Audit Committee of the Board of Directors, composed of outside directors only, meets with management, internal auditors, and independent accountants to review accounting, auditing, and financial reporting matters. The independent accountants are appointed by the Board on recommendation of the Audit Committee, subject to stockholder approval.

/s/ Howard E. Cosgrove

HOWARD E. COSGROVE
Chairman of the Board
and Chief Executive Officer

/s/ John C. van Roden

JOHN C. VAN RODEN
Senior Vice President and
Chief Financial Officer

February 5, 1999

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
Atlantic City Electric Company
Wilmington, Delaware

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 14(a)(1) on page IV-1 present fairly, in all material respects, the financial position of Atlantic City Electric Company and subsidiary companies as of December 31, 1998, and the results of their operations and their cash flows for the year ended December 31, 1998, in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under Item 14(a)(2) on page IV-1 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audit. We conducted our audit of these statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
2400 Eleven Penn Center
Philadelphia, Pennsylvania
February 5, 1999

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
Atlantic City Electric Company
Wilmington, Delaware

We have audited the accompanying consolidated balance sheet of Atlantic City Electric Company and subsidiary as of December 31, 1997 and the related consolidated statements of income, changes in common stockholder's equity, and cash flows for each of the two years in the period ended December 31, 1997. Our audits also included the financial statement schedule for years ended December 31, 1997 and 1996 listed in the Index as Item 14. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audits 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 Atlantic City Electric Company and subsidiary at December 31, 1997 and the results of their operations and their cash flows for each of the two years in the period ended December 31, 1997, in conformity with generally accepted accounting principles. Also, in our opinion, such financial statement schedule for the years ended December 31, 1997 and 1996, 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.

/s/ DELOITTE & TOUCHE LLP

Deloitte & Touche LLP
February 2, 1998 (March 1, 1998, as to Note 4)
Parsippany, New Jersey

ATLANTIC CITY ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(Dollars in Thousands)

	For the Year Ended December 31,		
	1998	1997	1996
Operating Revenues			
Electric	$1,034,894	$1,068,534	$984,360
Other Services	2,719	16,356	5,287
	1,037,613	1,084,890	989,647
Operating Expenses			
Electric Fuel and Purchased Power	308,943	293,457	225,185
Cost of Sales—Other Services	5,465	13,566	6,742
Purchased Electric Capacity	173,741	180,250	179,282
Employee Separation and Other Merger-Related Costs	61,091	22,246	—
Merger-Related Impairment Loss on Assets Held for Sale	18,000	—	—
Operation and Maintenance	206,951	177,875	205,615
Depreciation	112,711	100,412	97,262
Taxes Other Than Income Taxes	41,843	107,032	110,441
	928,745	894,838	824,527
Operating Income	108,868	190,052	165,120
Other Income			
Allowance for Equity Funds Used During Construction	593	815	879
Other Income	8,028	14,595	11,275
	8,621	15,410	12,154
Interest Expense			
Interest Charges	63,940	64,501	64,847
Allowance for Borrowed Funds Used During Construction and Capitalized Interest	(957)	(1,003)	(976)
	62,983	63,498	63,871
Dividends on Preferred Securities of Subsidiary Trusts	6,052	5,775	1,428
Income Before Income Taxes	48,454	136,189	111,975
Income Taxes	18,178	50,442	36,958
Net Income	30,276	85,747	75,017
Dividends on Preferred Stock	3,436	4,821	9,904
Gain on Preferred Stock Redemption	2,545	—	—
Earnings Applicable to Common Stock	$ 29,385	$ 80,926	$ 65,113

See accompanying Notes to Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	For the Year Ended December 31,		
	1998	1997	1996
Cash Flows from Operating Actvities			
Net Income	$ 30,276	$85,747	$ 75,017
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and Amortization	117,285	109,000	104,408
Investment Tax Credit Adjustments, Net	(1,690)	(2,534)	(2,534)
Deferred Income Taxes, Net	(37,915)	3,330	3,982
Deferred Energy Costs	43,001	6,105	(2,095)
Prepaid State Sales Taxes	(19,522)	—	—
Prepaid State Excise Taxes	3,248	3,321	3,628
Unrecovered State Excise Taxes	9,560	9,560	9,560
Employee Separation and Merger-Related Costs	16,147	—	—
Net Change in:			
Accounts Receivable	(500)	(5,536)	5,795
Inventories	5,077	3,365	(2,523)
Accounts Payable	18,765	(14,370)	2,814
Other Current Assets and Liabilities (1)	19,198	(10,245)	(2,525)
Impairment Loss on Assets Held for Sale	18,000	—	—
Other, Net	21,687	(15,052)	23,960
Net Cash Provided by Operating Activities	242,617	172,691	219,487
Cash Flows from Investing Activities			
Capital Expenditures	(71,342)	(80,896)	(88,914)
Nuclear Decommissioning Trust Fund Deposits	(6,424)	(6,424)	(6,424)
Other, Net	(1,040)	2,916	(9,283)
Net Cash Used by Investing Activities	(78,806)	(84,404)	(104,621)
Cash Flows from Financing Activities			
Dividends:			
Common Stock	(81,450)	(80,857)	(82,163)
Preferred Stock	(3,436)	(4,821)	(9,904)
Issuances:			
Long-term Debt	85,000	87,600	—
Preferred Securities	25,000	—	70,000
Redemptions:			
Long-term Debt	(58,575)	(74,066)	(12,266)
Preferred Stock	(33,769)	(20,000)	(98,876)
Principal Portion of Capital Lease Payments	(12,295)	(8,588)	(7,146)
Net Change in Short-term Debt	(72,100)	7,150	34,405
Other, Net	(4,184)	2,616	(3,879)
Net Cash Used by Financing Activities	(155,809)	(90,966)	(109,829)
Net Change in Cash and Cash Equivalents	8,002	(2,679)	5,037
Cash and Cash Equivalents at Beginning of the Year	20,765	23,444	18,407
Cash and Cash Equivalents at End of the Year	$ 28,767	$20,765	$ 23,444

(1) Other than debt and deferred income taxes classified as current.

See accompanying Notes to Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

ASSETS

	December 31, 1998	December 31, 1997
Current Assets		
Cash and Cash Equivalents	$ 28,767	$ 20,765
Accounts Receivable	130,148	129,648
Allowance for Doubtful Accounts	(3,500)	(3,500)
Inventories, at Average Cost:		
Fuel (Coal and Oil)	27,233	29,159
Materials and Supplies	21,296	20,893
Deferred Energy Costs	—	27,424
Prepaid New Jersey Sales and Excise Tax	20,078	3,804
Deferred Income Taxes, Net	7,735	—
Other Prepayments	4,420	3,949
	236,177	232,142
Investments		
Funds Held by Trustee	102,765	88,743
Other Investments	112	9
	102,877	88,752
Property, Plant, and Equipment		
Electric Utility Plant	2,600,699	2,591,825
Less: Accumulated Depreciation	1,007,106	945,921
Net Utility Plant in Service	1,593,593	1,645,904
Utility Construction Work-in-Progress	97,955	106,806
Leased Nuclear Fuel, at Amortized Cost	35,003	38,795
Nonutility Property, Net	8,207	8,517
	1,734,758	1,800,022
Deferred Charges and Other Assets		
Unrecovered Purchased Power Costs	48,274	66,264
Deferred Recoverable Income Taxes	102,223	85,858
Unrecovered State Excise Taxes	35,594	45,154
Deferred Debt Refinancing Costs	28,043	30,002
Deferred Other Postretirement Benefit Costs	34,978	37,476
Unamortized Debt Costs	14,141	13,416
Prepaid Pension Benefit	—	8,390
Other	30,157	29,279
	293,410	315,839
Total Assets	$2,367,222	$2,436,755

See accompanying Notes to Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

CAPITALIZATION AND LIABILITIES

	December 31, 1998	December 31, 1997
Current Liabilites		
Short-term Debt	$ —	$ 55,675
Long-term Debt Due Within One Year	30,075	—
Variable Rate Demand Bonds	22,600	22,600
Accounts Payable	54,315	37,779
Interest Accrued	14,774	19,562
Dividends Payable	22,236	21,215
Taxes Accrued	22,916	5,922
Current Capital Lease Obligation	15,728	15,653
Accrued Employee Separation & Other Merger-related Costs	9,554	—
Deferred Energy Costs	15,577	—
Deferred Income Taxes, Net	—	9,974
Other	28,771	37,226
	236,546	225,606
Deferred Credits and Other Liabilities		
Deferred Income Taxes, Net	343,429	354,127
Deferred Investment Tax Credits	42,142	44,043
Long-term Capital Lease Obligation	19,523	24,077
Pension Benefit Obligation	10,477	—
Other Postretirement Benefit Obligation	44,607	37,476
Other	24,097	23,299
	484,275	483,022
Capitalization		
Common Stock, $3 Par Value; 25,000,000 Shares Authorized; Shares Outstanding; 1998 and 1997 18,320,937	54,963	54,963
Additional Paid-in Capital	493,007	493,161
Retained Earnings	182,123	234,909
Total Common Stockholder's Equity	730,093	783,033
Preferred Stock Subject to Mandatory Redemption	23,950	33,950
Preferred Stock Not Subject to Mandatory Redemption	6,231	30,000
ACE Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely ACE Debentures	95,000	70,000
Long-term Debt	791,127	811,144
	1,646,401	1,728,127
Commitments and Contingencies (Notes 11 & 12)		
Total Capitalization and Liabilities	$2,367,222	$2,436,755

See accompanying Notes to Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCKHOLDER'S EQUITY
(Dollars in Thousands)

		Additional Paid-in Capital			
	Common Stock	Premium Capital Stock	Contri-buted Capital	Capital Stock Expense	Retained Earnings
Balance, December 31, 1995	$54,963	$231,081	$259,645	$(2,131)	$252,484
Net Income					75,017
Capital Stock Expense				486	(486)
Capital Contributed from Parent, Net			(567)		
Less Dividends:					
Preferred Stock					(9,904)
Common Stock					(82,163)
Balance, December 31, 1996	54,963	231,081	259,078	(1,645)	234,948
Net Income					85,747
Capital Stock Expense				108	(108)
Capital Contributed from Parent, Net			4,539		
Less Dividends:					
Preferred Stock					(4,821)
Common Stock					(80,857)
Balance, December 31, 1997	54,963	231,081	263,617	(1,537)	234,909
Net Income					30,276
Preferred Stock Redemption		(64)		199	1,824
Capital Contributed from Parent, Net			(289)		
Less Dividends:					
Preferred Stock					(3,436)
Common Stock					(81,450)
Balance, December 31, 1998	$54,963	$231,017	$263,328	$(1,338)	$182,123

As of December 31, 1998, ACE had 25 million authorized shares of common stock at $3 par value. Shares outstanding at December 31, 1998, 1997 and 1996 were 18,320,937.

See accompanying Notes to Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

As discussed in Note 4 to the Consolidated Financial Statements, effective March 1, 1998, Atlantic Energy, Inc. (Atlantic), and Delmarva Power & Light (DPL) consummated a series of merger transactions (the Merger) by which Atlantic City Electric Company (ACE) and DPL became wholly-owned subsidiaries of Conectiv.

ACE is a public utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity. Sales of electricity include sales at regulated retail and unregulated wholesale levels. Subsequent to the Merger, unregulated wholesale or bulk power sales have been transacted through DPL, in order to achieve Merger synergies. ACE serves approximately 488,800 customers within its service territory, which covers an area of approximately 2,700 square miles within the southern one-third of New Jersey and has a population of approximately 850,000. The majority of customers are residential and commercial.

Principles of Consolidation

The consolidated financial statements include the accounts of ACE and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and 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 and assumptions.

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year reporting of these items.

Regulation of Utility Operations

ACE is subject to regulation with respect to retail electric sales by the New Jersey Board of Public Utilities (NJBPU). The Federal Energy Regulatory Commission (FERC) also has regulatory authority over certain aspects of ACE's business, including the transmission of electricity, the sale of electricity to municipalities and electric cooperatives, and interchange and other purchases and sales of electricity involving other utilities.

ACE is subject to the requirements of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." The NJBPU occasionally provides for future recovery from customers of current period expenses. When this happens, the expenses are deferred as regulatory assets and subsequently recognized in the Consolidated Statement of Income during the period the utility expenses are recovered from customers. Similarly, regulatory liabilities may also be created due to the economic impact of an action taken by the NJBPU. See Notes 3, 5 and 14 to the Consolidated Financial Statements for additional information.

Revenue Recognition

At the end of each month, there is an amount of electric service rendered from the last meter reading to the month-end, which has not yet been billed to customers. The revenues associated with such unbilled services are

accrued by ACE and the accrued amounts receivable for unbilled electric service were $29.7 million as of December 31, 1998 and $36.9 million as of December 31, 1997. When interim rates are placed in effect subject to refund, ACE recognizes revenues based on expected final rates.

Revenues from ''Other services'' are recognized when services are performed or products are delivered.

Nuclear Fuel

ACE's share of nuclear fuel at the Peach Bottom Atomic Power Station (Peach Bottom), the Salem Nuclear Generating Station (Salem), and the Hope Creek Nuclear Generating Station (Hope Creek) is financed through contracts accounted for as capital leases. Nuclear fuel costs, including a provision for the future disposal of spent nuclear fuel, are charged to fuel expense on a unit-of-production basis.

Electric Utility Plant and Allowance for Funds Used During Construction

Electric utility plant is stated at original cost, including property additions. Generally, utility plant is subject to a First Mortgage lien. Allowance for Funds Used During Construction (AFUDC) is included in the cost of utility plant and represents the cost of borrowed and equity funds used to finance construction of new utility facilities. In the Consolidated Statements of Income, the borrowed funds component of AFUDC is reported as a reduction of interest expense and the equity funds component of AFUDC is reported as other income. AFUDC has been calculated using a semi-annually compounded rate of 8.25% for all periods.

Depreciation

ACE provides for straight-line depreciation based on the following: transmission and distribution property—estimated remaining life; nuclear property—remaining life of the related plant operating license in existence at the time of the last base rate case; other depreciable property—estimated average service life. Depreciation expense includes a provision for ACE's share of the estimated cost of decommissioning nuclear power plant reactors based on site-specific studies. Refer to Note 15 to the Consolidated Financial Statements for additional information on nuclear decommissioning. ACE's overall composite rate of depreciation was 3.9% for 1998 and 3.3% for 1997 and 1996. Accumulated depreciation is charged with the cost of depreciable property retired including removal costs less salvage and other recoveries.

Funds Held by Trustee

Funds held by trustee are stated at fair market value and primarily include deposits for nuclear decommissioning costs.

Deferred Energy Costs

As approved by the NJBPU, ACE has a Levelized Energy Clause (LEC) through which energy and energy-related costs (energy costs) are charged to customers. LEC rates are based on projected energy costs and prior period underrecoveries or overrecoveries. Generally, energy costs are recovered through levelized rates over the period of projection, which is usually a 12-month period. In any period, the actual amount of LEC revenues recovered from customers may be greater or less than the recoverable amount of energy costs incurred in that period. Electric Fuel and Purchased Power expenses are adjusted to match the associated LEC revenues. Any underrecovery (an asset representing energy costs incurred that are to be collected from customers) or overrecovery (a liability representing previously collected energy costs to be returned to customers) of costs is deferred on the Consolidated Balance Sheet as Deferred Energy Costs. These deferrals are recognized in the Consolidated Statement of Income during the period in which they are subsequently included in the LEC rates.

Income Taxes

The consolidated financial statements include two categories of income taxes—current and deferred. Current income taxes represent the amounts of tax expected to be reported on ACE's federal and state income tax returns. Deferred income taxes are discussed below.

Deferred income tax assets and liabilities represent the tax effects of temporary differences between the financial statement and tax bases of existing assets and liabilities and are measured using presently enacted tax rates. The portion of ACE's deferred tax liability applicable to utility operations that has not been recovered from utility customers represents income taxes recoverable in the future and is shown on the Consolidated Balance Sheets as "Deferred recoverable income taxes." Deferred recoverable income taxes were $102.2 million and $85.9 million as of December 31, 1998, and 1997, respectively.

Deferred income tax expense represents the net change during the reporting period in the net deferred tax liability and deferred recoverable income taxes.

Investment tax credits from utility plant purchased in prior years are reported on the Consolidated Balance Sheets as "Deferred investment tax credits." These investment tax credits are being amortized to income over the useful lives of the related utility plant.

Energy Trading and Risk Management Activities

Since the Merger, ACE has not used derivative financial instruments because ACE ceased its unregulated electricity trading activities. In 1997, to minimize the risk of market fluctuations associated with unregulated electricity trading, ACE entered into various transactions involving derivative financial instruments for hedging purposes. Gains or losses associated with the derivative transactions were recognized in operations in the period the derivative instrument was terminated or extinguished or ceased to be qualified as a hedge.

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133, " Accounting for Derivative Instruments and Hedging Activities," which becomes effective in the first quarter of fiscal years beginning after June 15, 1999, unless early adoption is elected. SFAS No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires that all derivatives be recognized as assets or liabilities in the balance sheet and be measured at fair value. Under specified conditions, a derivative may be designated as a hedge. The change in the fair value of derivatives which are not designated as hedges is recognized in earnings. For derivatives designated as hedges of changes in the fair value of an asset or liability, or as a hedge of exposure to variable cash flows of a forecasted transaction, earnings are affected to the extent the hedge does not match offsetting changes in the hedged item. ACE currently cannot determine the effect that SFAS No. 133 will have on its financial statements.

Cash Equivalents

ACE considers all highly liquid investments and debt securities purchased with a maturity of three months or less to be cash equivalents.

Debt Costs

Debt premium, discount and expense are amortized over the life of the related debt. Costs associated with refinancing debt are deferred and amortized over the life of the new debt.

2. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid during the year

(Dollars in Thousands)	1998	1997	1996
Interest	$68,278	$64,966	$65,269
Taxes, net of refunds	$48,215	$48,400	$36,937

3. INCOME TAXES

ACE, as a subsidiary of Conectiv, is included in the consolidated federal income tax return of Conectiv. Income taxes are allocated to ACE based upon its taxable income or loss, determined on a separate return basis.

The components of income tax expense for the years ended December 31, 1998, 1997, and 1996 are as follows:

(Dollars in Thousands)	1998	1997	1996
Federal:			
Current	$43,133	$49,646	$35,510
Deferred	(27,694)	3,330	3,982
State:			
Current	14,650	—	—
Deferred	(10,221)	—	—
Investment tax credit adjustments	(1,690)	(2,534)	(2,534)
	$18,178	$50,442	$36,958

The amount computed by multiplying income before tax by the federal statutory rate is reconciled below to the total income tax expense.

	1998		1997		1996	
(Dollars in Thousands)	Amount	Rate	Amount	Rate	Amount	Rate
Statutory federal income tax expense	$16,959	35%	$47,666	35%	$39,191	35%
State income taxes, net of federal tax benefit	2,878	6	—	—	—	—
Plant basis differences	3,767	8	4,952	4	3,096	3
Amortization of investment tax credits	(1,690)	(3)	(2,534)	(2)	(2,534)	(2)
Other, net	(3,736)	(8)	358	—	(2,795)	(3)
Total income tax expense	$18,178	38%	$50,442	37%	$36,958	33%

Effective January 1, 1998, New Jersey eliminated the Gross Receipts and Franchise Tax paid by electric, natural gas and telecommunication public utilities. In its place, utilities are now subject to the state's corporate business tax. In addition, the state's existing sales and use tax was expanded to include retail sales of electric power and natural gas. A Transitional Energy Facility Assessment Tax (TEFA) on electric and natural gas utilities will be phased-out over a five-year period. On January 1, 1999, and each of the four years thereafter, the TEFA will be reduced by 20%. When fully implemented, the tax law changes will reduce ACE's effective state tax rate from 13% to approximately 7%. Savings from these changes in New Jersey tax law will be passed through to ACE's customers.

Items comprising deferred tax balances as of December 31, 1998 and 1997 are as follows:

(Dollars in Thousands)	1998	1997
Deferred tax liabilities:		
Utility plant basis differences	$274,773	$302,238
Deferred recoverable income taxes	35,944	30,050
Unrecovered purchase power costs	12,239	16,813
State excise taxes	12,822	16,326
Other	31,852	34,190
Total deferred tax liabilities	367,630	399,617
Deferred tax assets:		
Deferred investment tax credits	22,749	23,775
Other	9,187	11,741
Total deferred tax assets	31,936	35,516
Total deferred taxes, net	$335,694	$364,101

4. MERGER

On March 1, 1998, ACE and DPL became wholly-owned subsidiaries of Conectiv (the Merger). Before the Merger, Atlantic owned ACE and nonutility subsidiaries. As a result of the Merger, Atlantic no longer exists and Conectiv owns (directly or indirectly) ACE, DPL and the nonutility subsidiaries formerly held separately by Atlantic and DPL. Conectiv is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA).

The Merger was accounted for under the purchase method, with DPL as the acquirer. ACE's financial statements do not reflect "push-down" accounting—the adjustment of the values of assets and liabilities as of the Merger date and recording of goodwill. Push-down accounting was not used because ACE had preferred stock and public debt outstanding as of the Merger date.

Under the terms of the agreement, Atlantic stockholders received 0.75 shares of Conectiv's common stock and 0.125 shares of Conectiv's Class A common stock for each share of Atlantic stock held. DPL stockholders received one share of Conectiv's common stock for each share of DPL common stock held.

ACE has recorded the financial effects of enhanced retirement offers and other employee separation programs utilized to reduce the workforce by 354 positions. The employee separation programs and other Merger-related costs resulted in a $61.1 million pre-tax charge to expense (or $36.6 million after taxes) for the year ended December 31, 1998 and a $22.2 million pre-tax charge to expenses (or $15.6 million after taxes) for the year ended December 31, 1997. The pre-tax expenses are shown on the Statement of Income as "Employee separation and other merger-related costs." As of December 31, 1998, $35.4 million of the $61.1 million expense for the year ended December 31, 1998 had been paid, $16.1 million will not require the use of operating funds, and $9.6 million remains to be paid from operating funds.

As part of the Merger, ACE has consolidated its operational and administrative facilities throughout its regulated service territory, causing certain assets to be held for sale. The estimated fair market value of these assets is $18.0 million less than their aggregate carrying value of $32.7 million as of December 31, 1998. In accordance with, SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," ACE recorded in the fourth quarter of 1998 an estimated impairment loss of $18.0 million ($10.6 million net of taxes).

NOTE 5. RATE MATTERS

Electric Utility Industry Restructuring

As discussed below, the electric utility industry is being deregulated in New Jersey. Generally, the restructuring will deregulate the supply component of the price charged to a customer for electricity, and

electricity suppliers will compete to supply electricity to customers. Customers will continue to pay the local utility a regulated price for the delivery of the electricity over the transmission and distribution system.

Stranded costs are costs which may not be recoverable in a competitive energy supply market due to lower prices or customers choosing a different supplier. Stranded costs generally include above-market costs associated with generation facilities or long-term purchased power agreements, and regulatory assets. ACE has quantified stranded costs in a New Jersey regulatory filing and has proposed a plan seeking approval for recovery of those costs from customers during the transition to a competitive market.

When the NJBPU issues an order specifically addressing deregulation in ACE's service territory, ACE will cease applying SFAS No. 71 to its electricity supply business. To the extent that the NJBPU's order provides for recovery of stranded costs through cash flows from the regulated transmission and distribution business, the stranded costs would continue to be recognized as assets under SFAS No. 71. Any stranded costs (including regulatory assets) for which cost recovery is not provided would be expensed.

The amount of stranded costs ultimately recovered from utility customers, if any, and the full impact of New Jersey legislation deregulating the electric utility industry, as discussed below, cannot be predicted. Also, the quantification of stranded costs under existing GAAP differs from methods used in regulatory filings. Among other differences, GAAP precludes recognition of the gains on plants (or purchased power contracts) not impaired, but requires write down of the plants that are impaired. Due to these considerations, market conditions, timing and other factors, ACE's management currently cannot predict the ultimate effects that electric utility industry deregulation may have on the financial statements of ACE, although deregulation may have a material adverse effect on ACE's results of operations.

New Jersey Legislation

The "Electric Discount and Energy Competition Act" (the Act) was signed into law by the Governor of New Jersey on February 9, 1999. The Act provides for retail choice of electricity suppliers; deregulation of electric rates and other competitive services, such as metering and billing; separation of competitive and regulated services; unbundling of rates for electric service; and licensing of electric and gas suppliers. August 1, 1999 is the effective starting date for each utility to provide retail choice of electricity suppliers to all of its customers.

The Act requires each electric utility to reduce its rates by at least 5% at the start of retail choice and by 10% within 36 months of the start of choice. If the NJBPU determines that a rate decrease of more than 10% is warranted, a "just and reasonable" financial test is applied. The mandated rate reductions must be sustained through the end of the 48th month after choice begins. The Act requires that the rate reductions be measured against the rates in effect on April 30, 1997. The rate reductions mandated by the Act could have a material adverse effect upon the results of operations of ACE.

In connection with the deregulation of electric rates, the Act authorizes the NJBPU to permit electric public utilities to recover the full amount of their stranded costs through a non-bypassable market transition charge, as long as the mandated rate reductions are achieved. The NJBPU will determine the utility's stranded cost amount. The NJBPU-determined stranded cost amount will be subject to periodic recalculation and true-up over the recovery period. The Act establishes an 8-year recovery period for stranded costs associated with owned generation. The recovery period can be extended by the NJBPU so as to allow for the full recovery of the stranded costs and the meeting of mandated rate reductions. The recovery period for stranded costs associated with purchased power contracts is to be the remainder of the contract term. In addition, the Act would allow for the issuance of transition bonds to finance portions of a given utility's stranded costs, as determined to be appropriate by the NJBPU. All savings generated through the use of such transition bonds are to be provided to the customers through rate reductions.

The Act establishes the current incumbent utility as the provider of "default service" or Basic Generation Service (BGS) for a period of 3 years. Future proceedings will be held to determine if the provision of BGS

should be made competitive. The Act contains numerous provisions regarding the providing of competitive services by each utility. The primary focus is to ensure that there is no cross subsidization from the utility to competitive entities. The NJBPU also is required to develop fair competition standards and conduct an audit to determine that the utilities are in compliance with those standards. The Act gives the NJBPU the authority to order a utility to divest its generating assets if it is determined through a hearing that competition or customers are being adversely affected by plant location, market power or non-competitive rates. The NJBPU may require that the generation function be separated from a utility's non-competitive functions.

The NJBPU is authorized to establish standards for the licensing of energy suppliers, standards for switching customers from one supplier to another, and standards for issues such as credit and collections. The Act also contains provisions for protecting workers displaced by the impacts of the restructuring of the utility industry.

Stranded Cost Filing

Electric utilities in New Jersey, including ACE, previously filed stranded cost estimates and unbundled rates, as required by the NJBPU. On August 19, 1998, an Administrative Law Judge (ALJ) from the New Jersey Office of Administrative Law issued an initial decision on ACE's stranded costs and unbundled rate filing. The ALJ, in reviewing ACE's filing, recognized that ACE's stranded costs were $812 million for nonutility generation contracts and $397 million for owned generation. The ALJ made no specific recommendations on rate issues. A final NJBPU decision on this filing is expected by mid-1999.

Other Rate Matters

ACE is sharing a portion of the net cost savings expected to result from the Merger (see Note 4 to the Consolidated Financial Statements) with its customers through reduced electric retail customer base rates. ACE's total Merger-related electric base rate decrease of $15.7 million was phased-in as follows: (1) $5.0 million effective January 1, 1998 coincident with a $5.0 million increase for recovery of deferred other postretirement benefit costs (OPEB); (2) $9.9 million effective March 1, 1998, and (3) $0.8 million effective January 1, 1999.

ACE is subject to a performance standard for its five jointly-owned nuclear units. Under the standard, the composite target capacity factor for such units is 70%, based upon the maximum dependable capacity of the units. The zone of reasonable performance (deadband) is between 65% and 75%. Penalties or rewards are based on graduated percentages of estimated costs of replacement power. LEC rates are adjusted annually to include any penalty or reward resulting from the nuclear unit performance standard. Pursuant to a December 1996 stipulation agreement, the performance of Salem Units 1 and 2, during prolonged outages which began in the second quarter of 1995, is not included in the calculation of a nuclear performance penalty. ACE was not subject to a nuclear performance penalty in 1996, 1997 or 1998.

Refer to Note 3 to the Consolidated Financial Statements for information concerning rate changes related to changes in the New Jersey tax laws.

ACE submitted its second Demand Side Management (DSM) Plan for the period from September 1997 through August 1998 in April 1997. The DSM Plan includes programs that address energy conservation needs of the residential, commercial and industrial markets. During the course of DSM Plan proceedings, New Jersey's Division of the Ratepayer Advocate (Ratepayer Advocate) alleged that ACE has been recovering more in rates for DSM programs than it is spending on such programs. ACE's position is that the level of DSM expenditures cannot be viewed in isolation, but must be considered in light of both the overall history of DSM expenditures under current rates, as well as ACE's overall revenue requirement needs in a rate proceeding. The Ratepayer Advocate contends that any over-recovery and treatment of such over-recovery should be addressed outside the context of a base rate proceeding. The NJBPU has not yet taken any action on this matter. ACE cannot predict the outcome of this matter.

NOTE 6. PENSION AND OTHER POSTRETIREMENT BENEFITS

Assumptions	1998	1997	1996
Discount rates used to determine projected benefit obligation as of December 31	6.75%	7.00%	7.50%
Rates of increase in compensation levels	4.50%	3.50%	3.50%
Expected long-term rates of return on pension assets	9.00%	9.00%	8.50%
Expected long-term rates of return on other postretirement benefit assets	9.00%	7.00%	7.00%
Health care cost trend rate on covered charges	7.00%	7.50%	8.00%

The health-care cost trend rate, or the expected rate of increase in health-care costs, is assumed to continue to gradually decrease to 5.0% by 2002. Increasing the health-care cost trend rates of future years by one percentage point would increase the accumulated postretirement benefit obligation by $11.8 million and would increase annual aggregate service and interest costs by $1.5 million. Decreasing the health-care cost trend rates of future years by one percentage point would decrease the accumulated postretirement benefit obligation by $10.4 million and would decrease annual aggregate service and interest costs by $1.3 million.

The following schedules reconcile the beginning and ending balances of the pension and other postretirement benefit obligations and related plan assets. Other postretirement benefits include medical benefits for retirees and their spouses and retiree life insurance.

Change in Benefit Obligation

	Pension Benefits		Other Postretirement Benefits	
(Dollar in Thousands)	1998	1997	1998	1997
Benefit obligation at beginning of year	$239,000	$207,340	$103,824	$107,105
Service cost	7,558	6,763	3,643	2,531
Interest cost	20,583	15,840	8,816	6,843
Plan amendments	(10,622)	—	—	—
Actuarial (gain) loss	90,862	25,122	15,460	(7,955)
Special termination benefits	11,846	—	1,270	—
Curtailment (gain) loss	(3,883)	—	6,597	—
Settlement (gain) loss	318	4,475	—	—
Benefits paid	(54,722)	(20,540)	(4,275)	(4,700)
Benefit obligation at end of year	$300,940	$239,000	$135,335	$103,824

Change in Plan Assets

	Pension Benefits		Other Postretirement Benefits	
(Dollars in Thousands)	1998	1997	1998	1997
Fair value of assets at beginning of year	$259,500	$236,000	$ 20,100	$ 18,000
Actual return on plan assets	10,062	35,414	1,119	800
Employer contributions	—	8,626	13,261	6,000
Benefits paid	(54,722)	(20,540)	(4,275)	(4,700)
Fair value of assets at end of year	$214,840	$259,500	$ 30,205	$ 20,100

Reconciliation of Funded Status of the Plans

(Dollars in Thousands)	Pension Benefits 1998	Pension Benefits 1997	Other Postretirement Benefits 1998	Other Postretirement Benefits 1997
Funded status at end of year	$(86,100)	$20,500	$(105,130)	$(83,724)
Unrecognized net actuarial (gain) loss	86,070	(10,810)	27,886	4,727
Unrecognized prior service cost	(10,447)	232	—	—
Unrecognized net transition (asset) obligation	—	(1,532)	32,637	41,521
Net amount recognized at end of year	$(10,477)	$ 8,390	$ (44,607)	$(37,476)

Based on fair values as of December 31, 1998, the pension plan assets were comprised of publicly traded equity securities ($143.9 million or 67%) and fixed income obligations ($70.9 million or 33%). As of December 31, 1998, the other postretirement benefit plan assets were comprised entirely of fixed income securities.

Components of Net Periodic Benefit Cost

(Dollars in Thousands)	Pension Benefits 1998	Pension Benefits 1997	Pension Benefits 1996	Other Postretirement Benefits 1998	Other Postretirement Benefits 1997	Other Postretirement Benefits 1996
Service cost	$ 7,558	$ 6,763	$ 6,870	$ 3,643	$2,531	$2,688
Interest cost	20,583	15,840	14,569	8,816	6,843	7,482
Expected return on assets	(20,414)	(20,160)	(17,376)	(1,015)	(1,275)	(1,122)
Amortization of:						
Transition obligation (asset)	(41)	24	24	2,404	2,768	2,768
Prior service cost	20	(172)	(172)	50	—	—
Actuarial loss	2,131	263	204	710	—	566
Cost before items below	9,837	2,558	4,119	14,608	10,867	12,382
Special termination benefits	11,846	—	—	1,270	—	—
Curtailment (gain) loss	(3,883)	5,932	—	6,597	—	—
Settlement loss	318	330	—	—	—	—
Total net periodic benefit cost	$ 18,118	$ 8,820	$ 4,119	$ 22,475	$ 10,867	$ 12,382
Portion of net periodic benefit cost included in results of operations	$15,514	$ 8,162	$ 3,040	$19,553	$3,640	$3,104

The components of 1998 and 1997 pension and other postretirement periodic benefit costs attributed to special benefits, curtailment (gain) loss, and settlement loss resulted from the enhanced retirement offer and other employee separation programs associated with the Merger.

Other postretirement benefit costs in excess of the amount recovered in customer rates were deferred from 1993 to 1997, including $4.9 million in 1997 and $6.4 million in 1996. ACE began to recover these costs, through customer rates, over a 15 year period beginning in 1998. See Note 5 and Note 14 to the Consolidated Financial Statements for additional information.

Effective January 1, 1999, ACE's covered employees began participating in a "cash balance" pension plan adopted by Conectiv. Contributions, which vary based on the covered employee's age and years of service, will

be made to individual employee accounts provided for under the plan. The "cash balance" of each employee's account increases based on employer contributions and interest income credited to the account. The aggregate of the employee's accounts will be ACE's pension obligation.

During 1998, ACE's covered employees began participating in the Conectiv 401(k) plans. Conectiv contributes to the plans, in the form of Conectiv stock, at varying levels up to $0.50 for each dollar contributed by covered employees, for up to 6% of employee base pay. Prior to the Merger, ACE had 401(k) plans for its employees, under which ACE contributed up to $0.50 for each dollar contributed by covered employees, for up to 6% of employee base pay. The cost of the plans for 1998, 1997, and 1996 was $1.9 million, $2.0 million and $1.9 million, respectively.

7. JOINTLY-OWNED GENERATING STATIONS

ACE owns jointly with other utilities several electric generating facilities. ACE is responsible for its pro-rata share of the costs of construction, operation and maintenance of each facility. ACE provides financing during the construction period for its share of the jointly-owned facilities and includes its share of direct operations and maintenance expenses in the Consolidated Statements of Income.

The amounts shown below represent ACE's share of each facility at, or for the year ended, December 31, 1998, including AFUDC as appropriate.

(Dollars in Thousands)	Keystone	Cone-maugh	Peach Bottom	Salem	Hope Creek
Energy Source	Coal	Coal	Nuclear	Nuclear	Nuclear
Ownership Share	2.47%	3.83%	7.51%	7.41%	5.00%
MW Capability Owned	42	65	164	164	52
Electric Plant in Service	$13,640	$33,956	$135,775	$245,628	$241,062
Accumulated Depreciation*	$ 3,815	$ 8,310	$ 62,688	$ 90,120	$ 82,854
Construction Work in Progress	$ 104	$ 456	$ 13,037	$ 7,260	$ 1,251

* Excludes Nuclear Decommissioning Reserve.

8. CUMULATIVE PREFERRED SECURITIES

ACE has authorized 799,979 shares of Cumulative Preferred Stock, $100 Par Value, two million shares of No Par Preferred Stock and three million shares of Preference Stock, No Par Value. If preferred dividends are in arrears for at least a full year, preferred stockholders have the right to elect a majority of directors to the Board of Directors until all dividends in arrears have been paid.

Preferred Stock Subject to Mandatory Redemption

	1998		1997	
Series	Shares	(000)	Shares	(000)
$8.20, no par value	—	$ —	100,000	$10,000
$7.80, no par value	239,500	23,950	239,500	23,950
Total	239,500	$23,950	339,500	$33,950

Beginning May 1, 2001, 115,000 shares of the remaining $7.80 No Par Preferred Stock must be redeemed annually through the operation of a sinking fund at a redemption price of $100 per share. ACE has the option to redeem up to an additional 115,000 shares without premium on any annual sinking fund date.

ACE redeemed its $8.20 No Par Preferred Stock ($100 per share stated value) as follows: 100,000 shares in August 1998; 200,000 shares in August 1997, and 200,000 shares in August 1996. In September 1996, ACE

redeemed the remaining 50,000 shares of its $8.25 Preferred Stock ($100 per share stated value). In August 1996, ACE repurchased 460,500 shares of its $7.80 No Par Preferred Stock ($100 per share stated value). In February 1996, ACE redeemed the remaining 120,000 shares of its $8.53 No Par Preferred Stock ($100 per share stated value).

Preferred Stock Not Subject to Mandatory Redemption

Series	1998 Shares	1998 (000)	1997 Shares	1997 (000)	Current Redemption Price
4%, $100 par value	24,268	$2,427	77,000	$ 7,700	$105.50
4.1%, $100 par value	20,504	2,051	72,000	7,200	101.00
4.35%, $100 par value	3,102	310	15,000	1,500	101.00
4.35%, $100 par value	1,680	168	36,000	3,600	101.00
4.75%, $100 par value	8,631	863	50,000	5,000	101.00
5%, $100 par value	4,120	412	50,000	5,000	100.00
Total	62,305	$6,231	300,000	$30,000	

Cumulative Preferred Stock Not Subject to Mandatory Redemption is redeemable solely at the option of ACE. In October 1998, ACE purchased and retired 237,695 shares, or $23.77 million of various series of mandatorily redeemable preferred stock, which had an average dividend rate of 4.4%. ACE realized a $2.5 million gain on this preferred stock redemption which is presented as Gain on Preferred Stock Redemption within the 1998 Consolidated Statement of Income. In September 1996, ACE redeemed 100,000 shares of its 7.52% Preferred Stock $100 Par Value.

ACE Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of ACE

In November 1998, Atlantic Capital II, a wholly-owned subsidiary financing trust, issued $25 million in aggregate liquidation amount of 7⅜% Cumulative Trust Preferred Capital Securities (representing 1,000,000 preferred securities at $25 per security). At the same time, $25.8 million in aggregate principal amount of 7⅜% Junior Subordinated Debentures, Series I, due 2028 (7⅜% Debentures) were issued to Atlantic Capital II. For consolidated financial reporting purposes, the 7⅜% Debentures are eliminated in consolidation against the trust's investment in the 7⅜% Debentures. The preferred trust securities are subject to mandatory redemption upon payment of the 7⅜% Debentures at maturity or upon redemption. The 7⅜% Debentures are subject to redemption, in whole or in part at the option of ACE, at 100% of their principal amount plus accrued interest, after an initial period during which they may not be redeemed and at any time upon the occurrence of certain events.

The combination, of the obligations of ACE, pursuant to the 7⅜% Debentures and ACE's guarantee of distributions with respect to trust securities, to the extent the trust has funds available therefor, constitute a full and unconditional guarantee by ACE of the obligations of the trust under the trust securities that the trust has issued. ACE is the owner of all of the common securities of the trust, which constitute approximately 3% of the liquidation amount of all of the trust securities issued by the trust.

Atlantic Capital I is a wholly-owned subsidiary financing trust which is structured similarly to Atlantic Capital II (discussed above). In October 1996, Atlantic Capital I, issued $70 million (2,800,000 shares) of 8.25% Cumulative Quarterly Income ACE Obligated Mandatorily Redeemable Preferred Securities with a stated liquidation preference of $25 each. Atlantic Capital I's sole investment is in ACE's 8.25% Junior Subordinated Deferrable Interest Debentures (8.25% Debentures). The 8.25% Debentures and Preferred Securities mature in 2026.

9. DEBT

Secured debt	Maturity Date	December 31, 1998	December 31, 1997
		(Dollars in Thousands)	
Medium Term Notes Series B (6.28%)	2/1/1998	$ —	$ 56,000
Medium Term Notes Series A (7.52%)	1999	30,000	30,000
Medium Term Notes Series B (6.83%)	2000	46,000	46,000
Medium Term Notes Series C (6.86%)	2001	40,000	40,000
Medium Term Notes Series C (7.02%)	2002	30,000	30,000
Medium Term Notes Series B (7.18%)	2003	20,000	20,000
Medium Term Notes Series D (6.00%)	2003	20,000	—
Medium Term Notes Series A (7.98%)	2004	30,000	30,000
Medium Term Notes Series B (7.125%)	2004	28,000	28,000
Medium Term Notes Series C (7.15%)	2004	9,000	9,000
Medium Term Notes Series B (6.45%)	2005	40,000	40,000
Medium Term Notes Series D (6.19%)	2006	65,000	—
6⅜% Pollution Control Series	12/1/2006	2,350	2,425
Medium Term Notes Series C (7.15%)	2007	1,000	1,000
Medium Term Notes Series B (6.76%)	2008	50,000	50,000
Medium Term Notes Series C (7.25%)	2010	1,000	1,000
6⅝% First Mortgage Bonds	8/1/2013	75,000	75,000
Medium Term Notes Series C (7.63%)	2014	7,000	7,000
Medium Term Notes Series C (7.68%)	2015	15,000	15,000
Medium Term Notes Series C (7.68%)	2016	2,000	2,000
6.80% Pollution Control Series A	3/1/2021	38,865	38,865
7% First Mortgage Bonds	9/1/2023	75,000	75,000
5.60% Pollution Control Series A	11/1/2025	4,000	4,000
7% First Mortgage Bonds	8/1/2028	75,000	75,000
6.15% Pollution Control Series A	6/1/2029	23,150	23,150
7.20% Pollution Control Series A	11/1/2029	25,000	25,000
7% Pollution Control Series B	11/1/2029	6,500	6,500
		758,865	729,940
Unsecured debt			
6.46% Medium Term Notes Series A	4/1/2002	20,000	20,000
6.63% Medium Term Notes Series A	6/2/2003	30,000	30,000
7.52% Medium Term Notes Series A	4/2/2007	5,000	5,000
7.50% Medium Term Notes Series A	4/2/2007	10,000	10,000
		65,000	65,000
7¼% Debentures	5/1/1998	—	2,500
Unamortized Premium and Discount-Net		(2,663)	(2,721)
Total Long Term Debt		821,202	794,719
Add: Short Term Debt to be Refinanced		—	16,425
Less: Current Portion of Long-Term Debt		(30,075)	—
Total Long Term Debt		791,127	811,144
Variable Rate Demand Bonds, Pollution Control Series A	2014	18,200	18,200
Variable Rate Demand Bonds, Pollution Control Series B	2017	4,400	4,400
Total Long Term Debt & Variable Rate Demand Bonds		$813,727	$833,744

Substantially all of ACE's utility plant is subject to the lien of the Mortgage and Deed of Trust dated January 15, 1937, as amended and supplemented, collateralizing ACE's First Mortgage Bonds and Secured Medium Term Notes.

Variable Rate Demand Bonds (VRDB) are classified as current liabilities because the VRDB are due on demand by the bondholder. However, bonds submitted to ACE for purchase are remarketed by a remarketing agent on a best efforts basis. ACE expects that bonds submitted for purchase will continue to be remarketed successfully due to ACE's credit worthiness and the bonds' interest rates being set at market. ACE also may utilize one of the fixed rate/fixed term conversion options of the bonds. Thus, ACE considers the VRDB to be a source of long-term financing. Average interest rates on the VRDB were 3.2% for 1998 and 3.6% for 1997.

ACE funds its interim financing requirements by issuing commercial paper and borrowing against bank credit lines. At December 31, 1998, ACE had no outstanding short-term debt and had total bank credit lines of $195 million, all of which was available for borrowing. ACE's weighted daily average interest rate on short-term debt outstanding at December 31, 1997 was 5.8%.

On January 12, 1998, ACE issued $85 million of Secured Medium Term Notes, Series D maturing in January 2003 and January 2006 (6.1% average interest rate). The net proceeds received by ACE from the issuance of the Medium Term Notes was used to repay short-term debt and long-term debt (see schedule below) and $10 million of $8.20 No Par Preferred Stock in 1998.

The following schedule shows debt redemptions made, at maturity in 1998.

Series	Maturity Date	Principal
(Dollars in Thousands)		
6.35% Medium-Term Notes	1/26/98	$ 4,000
6.37% Medium-Term Notes	1/27/98	46,000
7.25% Debentures	5/01/98	2,500
5.50% Medium-Term Notes	5/14/98	6,000
6.375% Pollution Control Bonds*	12/01/09	75
		$58,575

* Annual sinking fund requirement on bonds due December 1, 2006.

Maturities and Sinking Fund Requirements for Long-Term Debt

(Dollars in thousands)	
1999	$30,075
2000	46,075
2001	40,075
2002	50,075
2003	70,075

10. COMMON STOCKHOLDER'S EQUITY

For information concerning changes to the common equity accounts of ACE, see the Consolidated Statements of Changes in Common Stockholder's Equity.

Effective March 1, 1998, all of the outstanding shares of ACE were acquired by Conectiv, pursuant to the Merger, as discussed in Note 4 to the Consolidated Financial Statements.

Under ACE's certificate of incorporation, ACE is subject to certain limitations on the payment of dividends to Conectiv, which is the holder of all of ACE's common stock. When full dividends have been paid on the Preferred Stock Securities of ACE for all past dividend periods, dividends may be declared and paid by ACE on

its common stock, as determined by the Board of Directors of ACE, out of funds legally available for the payment of dividends.

11. COMMITMENTS

Construction Program

Capital expenditures for 1999 are estimated to be approximately $85.4 million.

Purchased Capacity and Energy Arrangements

ACE arranges with various providers of bulk energy to obtain sufficient supplies of capacity and energy. Terms of the arrangements vary in length to enable ACE to optimally manage its supply portfolio in response to changing market conditions. At December 31, 1998, ACE has contracted for 828 megawatts (MWs) of purchased capacity with terms remaining of 1 to 26 years. Information regarding these arrangements relative to ACE was as follows:

	1998	1997	1996
Percentage of MW capacity	33%	29%	30%
Percentage of energy output	41%	54%	55%
Capacity charges (millions)	$173	$180	$179
Energy charges (millions)	$126	$137	$145

Electric capacity purchased from certain nonutility suppliers is recoverable through the LEC, which amounted to $166.9 million, $166.8 million and $165.3 million in 1998, 1997 and 1996, respectively. Based on existing contracts as of December 31, 1998, ACE's future commitments for capacity and energy under long-term purchased power contracts are estimated to be $269 million in 1999; $275 million in 2000; $266 million in 2001; $266 million in 2002; $268 million in 2003. Due to uncertainties surrounding restructuring of the electric utility industry, ACE has not forecasted its long-term purchased power commitments beyond 2003.

Leases

ACE has a contractual obligation to obtain nuclear fuel for the Salem, Hope Creek and Peach Bottom stations. The asset and related obligation for the leased fuel are reduced as the fuel is burned and are increased as additional fuel purchases are made. ACE's obligation under the contract is generally the net book value of the nuclear fuel financed, which was $35.0 million as of December 31, 1998. Operating expenses for 1998, 1997 and 1996 include leased nuclear fuel costs of $11.7 million, $9.8 million and $8.7 million, respectively.

ACE also leases other types of property and equipment for use in its operations. Amounts charged to operating expenses for these leases were $4.6 million in 1998, $2.4 million in 1997 and $2.6 million in 1996. Future minimum rental payments for all non-cancellable lease agreements, excluding nuclear fuel, are less than $3.0 million per year for each of the next five years.

12. CONTINGENCIES

Environmental Matters

ACE is subject to regulation with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal, and limitation on land use by various federal, regional, state, and local authorities. Costs may be incurred to clean up facilities found to be contaminated due to past disposal practices. Federal and state statutes authorize governmental agencies to compel responsible parties to clean up certain abandoned or uncontrolled hazardous waste sites. ACE is a potentially responsible party at a state superfund site and has agreed, along with other responsible parties, to remediate the site pursuant to an Administrative Consent Order with the New Jersey Department of Environmental Protection. ACE is also a

defendant in an action to recover costs at a federal superfund site in Gloucester, New Jersey. There is $1.0 million included in ACE's current liabilities as of December 31, 1998, for remediation activities at these sites. ACE does not expect such future costs to have a material effect on its financial position or results of operations.

Nuclear Insurance

In conjunction with ACE's ownership interests in Peach Bottom, Salem, and Hope Creek, ACE could be assessed for a portion of any third-party claims associated with an incident at any commercial nuclear power plant in the United States. Under the provisions of the Price Anderson Act, if third party claims relating to such an incident exceed $200 million (the amount of primary insurance), ACE could be assessed up to $30.7 million on an aggregate basis for such third-party claims. In addition, Congress could impose a revenue-raising measure on the nuclear industry to pay such claims

The co-owners of Peach Bottom, Salem, and Hope Creek maintain property insurance coverage of approximately $2.8 billion for each unit for loss or damage to the units, including coverage for decontamination expense and premature decommissioning. In addition, ACE is a member of an industry mutual insurance company, which provides replacement power cost coverage in the event of a major accidental outage at a nuclear power plant. Under these coverages, ACE is subject to potential retrospective loss experience assessments of up to $5.4 million.

13. SALEM NUCLEAR GENERATING STATION

In December 1996, the NJBPU issued an Order approving a stipulation of settlement reached among the parties settling the issues primarily regarding replacement power costs related to an extended Salem outage, which began in the second quarter of 1995. The stipulations provided for recovery through LEC rates of ACE's replacement power costs for the Salem outage, up to each Salem Unit's agreed-upon return-to-service date (June 30, 1997 for Unit 1 and December 31, 1996 for Unit 2). The Salem Units returned to service in August 1997 (Unit 2) and April 1998 (Unit 1). As a result, unrecovered purchased power costs of $2.1 million in 1998 and $10.2 million in 1997 were expensed.

The stipulation of settlement approved by the NJBPU in December 1996 also provided customers with a $13 million base rate credit, primarily for resolution of issues associated with the extended Salem outage. ACE accrued the $13 million base rate credit in 1996 as a reduction of electric revenues.

As previously reported, on February 27, 1996, the co-owners of Salem, including ACE and DPL, filed a complaint in the United States District Court for New Jersey against Westinghouse Electric Corporation (Westinghouse), the designer and manufacturer of the Salem steam generators. The complaint, which sought to recover from Westinghouse the costs associated with and resulting from the cracks discovered in Salem's steam generators and with replacing such steam generators, alleged violations of federal and New Jersey Racketeer Influenced and Corrupt Organizations Acts, fraud, negligent misrepresentation and breach of contract. On November 4, 1998, the Court granted Westinghouse's motion for summary judgment with regard to the federal Racketeer Influenced and Corrupt Organizations Act claim, and dismissed the remaining state law claims without prejudice. On November 18, 1998, the co-owners re-filed their state law claims against Westinghouse in the Superior Court of New Jersey. The co-owners also filed an appeal of the District Court's dismissal with the United States Court of Appeals for the Third Circuit.

14. REGULATORY ASSETS

In conformity with generally accepted accounting principles, ACE's accounting policies reflect the financial effects of rate regulation and decisions issued by the NJBPU and the FERC. In accordance with the provisions

of SFAS No. 71, ACE defers expense recognition of certain costs and records an asset, as a result of the effects of rate regulation. Except for deferred energy costs, which are classified as a current asset or liability, these "regulatory assets" are included on ACE's Consolidated Balance Sheets under "Deferred Charges and Other Assets." The costs of these assets are either being recovered or are probable of being recovered through customer rates. Generally, the costs of these assets are recognized in operating expenses over the period the cost is recovered from customers. For information about the impact of electric utility industry restructuring on accounting for regulatory assets, see Note 5 to the Consolidated Financial Statements.

The table shown below details total regulatory assets as of December 31, 1998 and 1997.

(Dollars in Thousands)	1998	1997	Remaining Amortization/ Recovery Period*
Deferred recoverable income taxes	$102,223	$ 85,858	(A)
Unrecovered purchased power costs:			
Capacity costs	30,608	48,038	2 years
Contract renegotiation costs	17,666	18,226	16 years
Unrecovered state excise taxes	35,594	45,154	4 years
Deferred debt refinancing costs	28,043	30,002	1-28 years
Under (Over) recovered deferred energy costs	(15,577)	27,424	(B)
Deferred other postretirement benefit costs	34,978	37,476	14 years
Asbestos removal costs	8,546	8,816	31 years
Nuclear decontamination and decommissioning of federally-owned nuclear units	6,217	5,032	10 years
Other	10,253	10,789	1-5 years
	$258,551	$316,815	

* From December 31, 1998

(A) Amortized as temporary differences between the financial statement and tax bases of assets and liabilities reverse.

(B) Recovered from or credited to customers over annual LEC Period.

Deferred recoverable income taxes represent the portion of ACE's deferred tax liability applicable to utility operations that has not been recovered from customers and is recoverable in the future.

Unrecovered purchased power capacity costs represent prior deferrals of capacity costs which had exceeded the related cost recovery from customers.

Unrecovered purchased power contract renegotiation costs were incurred through renegotiation of a long-term capacity and energy contract with a certain independent power producer.

Unrecovered state excise taxes represent additional amounts paid as a result of prior legislative changes in the computation of state excise taxes.

Deferred debt refinancing costs represent costs incurred to refinance debt and are amortized over the life of the related new debt.

Deferred other postretirement benefit costs represent the non-cash portion of OPEB costs deferred during 1993-1997.

Asbestos removal costs were incurred to remove asbestos insulation from a wholly-owned generating station.

Nuclear decontamination and decommissioning costs represent costs associated with decommissioning and decontaminating United States Department of Energy gaseous diffusion enrichment facilities.

Other includes certain amounts being recovered over periods of one to five years.

15. NUCLEAR PLANT DECOMMISSIONING

ACE has a trust to fund the future costs of decommissioning each of the five nuclear units in which it has an ownership interest. The current annual funding amount, as authorized by the NJBPU, totals $6.4 million and is provided for in rates charged to customers. The funding amount is based on estimates of the future cost of decommissioning each of the units; the dates that decommissioning activities are expected to begin and the return expected to be earned by the assets of the fund. The present value of ACE's nuclear decommissioning obligation is estimated to be $185 million based on site specific studies filed with and approved by the NJBPU. Decommissioning activities as approved by the NJBPU are expected to begin in 2006 and continue through 2032.

ACE's accrued nuclear decommissioning liability, which is reflected in the accumulated reserve for depreciation, was $98.2 million as of December 31, 1998. The provision reflected in depreciation expense for nuclear decommissioning was $6.4 million annually for 1998, 1997 and 1996. External trust funds established by ACE for the purpose of funding nuclear decommissioning costs had an aggregate book balance (stated at fair market value) of $98.2 million as of December 31, 1998. Earnings on the trust funds are recorded as an increase to the accrued nuclear decommissioning liability, which, in effect, reduces the expense recorded for nuclear decommissioning.

The staff of the Securities and Exchange Commission has questioned certain of the current accounting practices of the electric utility industry, including ACE, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In February 1996, the FASB issued the Exposure Draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets," which proposed changes in the accounting for closure and removal costs of long-lived assets, including the recognition, measurement, and classification of decommissioning costs for nuclear generating stations. If the proposed changes were adopted: (1) annual provisions for decommissioning would increase, (2) the estimated cost for decommissioning would be recorded as a liability rather than as accumulated depreciation, and (3) trust fund income from the external decommissioning trusts would be reported as investment income rather than as a reduction of decommissioning expense. The FASB expects to issue a revised Exposure Draft in the second quarter of 1999.

16. FAIR VALUE OF FINANCIAL INSTRUMENTS

A number of items within Current Assets and Current Liabilities on the Consolidated Balance Sheet are considered to be financial instruments because they are cash or are to be settled in cash. Due to their short-term nature, the carrying values of these items approximate their fair market values. Accounts Receivable—Utility Service and Unbilled Revenues are subject to concentration of credit risk because they pertain to utility service conducted within a fixed geographic region.

The year-end fair value of certain financial instruments are listed below. The fair values were based on quoted market prices of ACE's securities or securities with similar characteristics.

	1998		1997	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(Dollars in Millions)			
Funds Held By Trustee	$102.8	$102.8	$88.7	$88.7
Long Term Debt	791.1	832.6	811.1	836.9
Preferred Stock Subject to Mandatory Redemption	24.0	24.1	34.0	37.0
Preferred Securities*	95.0	98.3	70.0	72.3

* ACE Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of ACE

17. QUARTERLY FINANCIAL RESULTS (UNAUDITED)

Quarterly financial data, reflecting all adjustments necessary in the opinion of management for a fair presentation of such amounts, are presented below. Certain prior year amounts have been reclassified, not affecting net income, to conform to the current year reporting of these items. Third quarter results generally exceed those of other quarters due to increased sales and higher residential rates.

Quarter Ended	Operating Revenues	Operating Income/(Loss)	Net Income/(Loss)	Earnings(Loss) Applicable to Common Stock
	(Dollars in Thousands)			
1998				
March 31	$ 237,949	$ (17,823)	$(20,737)	$(21,737)
June 30	241,883	46,028	19,314	18,314
September 30	331,403	87,761	41,550	40,687
December 31	226,378	(7,098)	(9,851)	(7,879)
	$1,037,613	$108,868	$ 30,276	$ 29,385
1997				
March 31	$ 243,422	$ 47,378	$ 20,371	$ 18,961
June 30	242,475	45,011	18,676	17,266
September 30	338,162	89,580	47,541	46,541
December 31	260,831	8,083	(841)	(1,842)
	$1,084,890	$190,052	$ 85,747	$ 80,926

As discussed in Note 4 to the Consolidated Financial Statements, ACE recorded an impairment loss on assets held for sale in the fourth quarter of 1998 which reduced operating income $18.0 million and net income $10.6 million.

Employee separation programs and other Merger-related costs recorded in 1998 (as discussed in Note 4 to Consolidated Financial Statements) had the effects shown below on 1998 quarterly operating results.

Quarter Ended	Operating Incomne/(Loss)	Net Income/(Loss)	Earnings(Loss) Applicable to Common Stock
	(Dollars in Thousands)		
March 31	$(51,479)	$(30,946)	$(30,946)
June 30	3,361	1,987	1,987
September 30	(1,014)	(600)	(600)
December 31	(11,959)	(7,074)	(7,074)
	$(61,091)	$(36,633)	$(36,633)

Due to the Merger, various pension and compensation plans were terminated in the fourth quarter of 1997, resulting in a $22.2 million decrease in operating income and a $15.6 million decrease in net income.

18. BUSINESS SEGMENTS

Conectiv's organizational structure and management reporting information is aligned with Conectiv's business segments, irrespective of which subsidiary, or subsidiaries, a business is conducted through. Businesses are managed based on lines of business, not based on legal entity. Business segment information is not produced, or reported, on a subsidiary by subsidiary basis. Thus, as a Conectiv subsidiary, no business segment information (as defined by SFAS No. 131, ''Disclosures about Segments of an Enterprise and Related Information'') is available for ACE on a stand-alone basis.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Reference is made to Item 4 of Report on Form 8-K filed March 5, 1998.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Directors	Business Experience During Past 5 Years
As of December 31, 1998	
Howard E. Cosgrove, 55, ... Chairman of the Board	Elected 1998 as Chairman of the Board and Chief Executive Officer of Conectiv, Delmarva Power & Light Company, and Atlantic City Electric Company. Elected 1992 as Chairman of the Board, President and Chief Executive Officer and Director of Delmarva Power & Light Company.
Meredith I. Harlacher, Jr., 56, ... Director	Elected 1998 as President and Chief Operating Officer of Conectiv, and President and Chief Operating Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1993 as Senior Vice President of Atlantic Energy, Inc.
Barry R. Elson, 57, ... Director	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1997 as Executive Vice President, Delmarva Power & Light Company. Executive Vice President, Cox Communications, Inc., Atlanta, Georgia, from 1995 to 1996. Senior Vice President, Cox Enterprises/Cox Communications, Inc., Atlanta, Georgia, from 1984 to 1995.
Thomas S. Shaw, 51,..... Director	Elected 1998 as Executive Vice President of Conectiv, and Executive Vice President and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1992 as Senior Vice President, Delmarva Power & Light Company.
Barbara S. Graham, 50,..... Director	Elected 1998 as Senior Vice President and Chief Financial Officer of Conectiv, and Senior Vice President and Chief Financial Officer and Director of Delmarva Power & Light Company and Atlantic City Electric Company. Elected 1994 as Senior Vice President, Treasurer and Chief Financial Officer, Delmarva Power & Light Company. Vice President and Chief Financial Officer of Delmarva Power & Light Company from 1992 to 1994.

Executives

Information about ACE's executive officers is included under Item 1.

ITEM 11. EXECUTIVE COMPENSATION

As previously noted, ACE is a wholly owned electric utility subsidiary of Conectiv. The Chief Executive Officer and the four most highly compensated executive officers of Conectiv maintain the same position at both ACE and DPL. In 1998, the salaries and other compensation awarded to the Chief Executive Officer and the four most highly compensated executive officers of ACE were paid by Conectiv for their service as executive officers of Conectiv, ACE and DPL. The Board Personnel & Compensation Committee Report was provided initially in the Conectiv Proxy Statement and is enclosed herein for the purpose of providing additional informational. The following tables show information concerning the total compensation paid or awarded to ACE's Chief Executive Officer and each of the four most highly compensated executive officers for the fiscal year ended December 31, 1998.

Board Personnel & Compensation Committee Report

Principles of Executive Compensation Program

The Personnel & Compensation Committee of the Board of Directors is comprised of four non-employee Directors. The Committee provides an independent review of the Company's performance objectives and executive compensation.

Overall Objectives

The Company's philosophy is to link compensation to business strategies and results, to align total compensation of executives with the long-term interests of stockholders, to motivate its senior executives to meet the challenging objectives established for the Company and to create an urgency for success in the newly-formed Company. The Company's executive compensation program is designed to:

- provide total compensation that emphasizes long-term performance which creates stockholder value;
- facilitate the rapid transition to a competitive business environment;
- reflect the market conditions for attracting and retaining high-quality executives and ensure that such executives have a continuing stake in the long-term success of the Company; and
- create significant levels of stock ownership.

The elements of the executive compensation program are:

- total compensation levels that are competitive with those provided by the competitive market, defined as a blend of companies in the utility and industrial markets;
- base compensation levels related to responsibility level and individual performance;
- annual variable compensation that varies based on corporate, unit and individual performance; and,
- long-term variable compensation based on long-term increases in stockholder value.

Total Compensation

Total compensation opportunities are developed for Company executives by Watson Wyatt, the firm that provides executive compensation consulting services to the Company. This is done using several published compensation survey sources and public proxy data to define the competitive market. Overall, the total compensation structure for executives is targeted at the median for similar positions at companies of similar size, including both utilities and industrial companies (Compensation Comparison Group)[1]. Individual reward levels vary based on individual contributions and performance. Total compensation includes three components: base compensation, annual variable compensation and long-term variable compensation. The targets for each component of the executive compensation program are reviewed on an annual basis to ensure alignment with the Company's compensation philosophy and a proper balance between short-and long-term objectives.

1. The Compensation Comparison Group does not include all of the same companies as the published industry indices in the Comparison of 10 Month Cumulative Total Return chart included in this Proxy Statement. However, 34 of the 85 companies included in the EEI *Executive Compensation Report,* which is one element of the Compensation Comparison Group, are also part of either the Dow Jones Electric Utilities Index or the S&P 500 Index.

Base Compensation

Base compensation for executive officers is determined by evaluating the responsibilities of the positions held and the experience of the individuals, coupled with a review of compensation for comparable positions at other companies. Base compensation is reviewed on an annual basis and adjustments are based on the performance of the Company and each executive officer. Annual base compensation increases reflect the individual's performance and contribution over several years in addition to the results for a single year. Following the 1998 increases, the overall base compensation level for the five named executive officers was slightly below the median of the base compensation targeted levels defined by the surveys and proxies.

Annual Variable Compensation

The Company's annual variable compensation is designed to motivate participants to accomplish stretch financial and individual goals and to increase the sense of urgency to deliver significant results on an annual basis. Annual variable compensation target opportunities are designed to be at or above the median of the blended utility and industrial market and for the named executive officers vary from 40% to 50% of base compensation, with maximum awards of 60% to 75% of base compensation.

Annual variable compensation is paid in a combination of cash (80%) and restricted stock units (20%) and is based on the achievement of predetermined corporate and individual goals. The plan for 1998 provides that payouts will occur only after a specified earnings target is achieved.

For 1998, each individual covered by the plan was eligible to earn a variable compensation award between 0% and 150% of target. The portion of each individual award attributable to corporate, line of business, and group performance were determined and specific measures were developed at the beginning of the year. These measures were primarily financial for 1998 to accelerate the transition of the Company to a more competitive environment and included corporate measures of earnings, cash flow return on capital employed and cash flow. Each business group and line of business also developed specific financial measures to support their business plans.

The Management Stock Purchase Program (MSPP) was designed as a means to promote significant executive stock ownership in the new company and to help meet stock ownership guidelines. The program requires that 20% of the individual's earned annual variable compensation must be used to acquire restricted stock units (RSUs). Individuals may also voluntarily use up to an additional 30% (for a total of 50%) of their earned annual variable compensation to acquire RSUs. All RSUs are acquired at a 20% discount from Fair Market Value on the date paid. Each RSU is a proxy for one share of Common Stock, has a value equal to one share and earns at the rate of the Common Stock dividend. RSUs are restricted from sale or use for a 3-year period and are distributed in shares of Common Stock.

Long-Term Variable Compensation

The Company's long-term variable compensation reinforces the importance of providing stockholders with a competitive return on their investment. Long-term variable compensation awards also strengthen the ability of the Company to attract, motivate and retain executives of superior capability and more closely align the interests of management with those of stockholders.

Long-term grants for Conectiv executives are determined by setting a target percentage of base compensation based on median data in the Compensation Comparison Group and converting the target amounts to actual grants using the ''Black-Scholes Model'' for options and time and forfeiture discount methods for the other elements of the long-term grants.

Long-term awards granted in 1998 consisted of non-qualified stock options, dividend equivalent units and performance accelerated restricted stock. Non-qualified stock options and dividend equivalent units were awarded to provide approximately two-thirds of the targeted value of the grant while the other one-third of the

targeted value was provided through performance accelerated restricted stock. This stock vests as unrestricted Common Stock seven years from the award date. However, vesting may be accelerated if the price of Common Stock reaches certain predetermined levels prior to the seven years. All stock options were granted with exercise prices equal to the fair market value of Common Stock at the time of the grant.

Performance accelerated restricted stock granted to the CEO and three other named executive officers is also subject to an additional condition tied to Total Shareholder Return over the seven year period. Failure to meet a predetermined Total Shareholder Return level over the restriction period will result in total forfeiture of their shares granted.

The CEO and three other named executive officers also were given a special grant of performance accelerated stock options to increase emphasis on creating long-term shareholder value. All performance accelerated stock options were granted with exercise prices equal to the fair market value of Common Stock at the time of grant. These options do not vest and cannot be exercised for 9-1/2 years from the date of their grant unless the stock price increases to predetermined levels. Absent accelerated vesting at these predetermined stock prices, the shares will become exercisable in 9-1/2 years with expiration occurring at 10 years. This special grant resulted in the long-term variable compensation component and total compensation exceeding the targeted median values for these four executives for 1998 using the Black-Scholes valuation methodology.

Stock Ownership Guidelines

To further reinforce the interests of stockholders, stock ownership guidelines have been established for the Board of Directors, Company officers, and other Company management. These guidelines require the individuals covered by the guidelines to have beneficial ownership of Common Stock, or securities convertible into Common Stock, with an aggregate value equal to certain multiples of each individual's salary (or annual retainers in the case of outside directors). Multiples range from five times to one times salary. The Chief Executive Officer's multiple is set at five times salary and outside Directors' multiples are set at three times the annual retainer.

Internal Revenue Code Section 162(m)

The Committee considers the tax deductibility of compensation paid to executive officers and the impact of Section 162(m) of the Internal Revenue Code of 1986, as amended (the ''Code''), on the Company. This provision limits the amount of compensation that the Company may deduct from its taxable income for any year to $1 million for any of its five most highly compensated executive officers, unless certain requirements are met.

The Committee has taken actions to limit the impact of the Code in the event that compensation paid to a named executive officer might otherwise not be deductible. The Committee will continue to seek ways to limit the impact of the Code; however, the Committee believes that the tax deduction limitation should not compromise the Company's ability to create incentive programs that support the business strategy and also attract and retain the executive talent required to compete successfully. Accordingly, achieving the desired flexibility in the design and delivery of compensation may periodically result in some compensation that is not deductible for federal income tax purposes.

Summary of Actions Taken by the Personnel & Compensation Committee

The Personnel & Compensation Committee, consisting entirely of outside directors, provides direction and oversight to the Company's executive compensation plans, establishes the Company's compensation philosophy and assesses the effectiveness of the program as a whole. This includes activities such as reviewing the design of various plans and assessing the reasonableness of the total program consistent with the total compensation philosophy.

The Committee also assists in administering key aspects of the Company's annual compensation program and variable compensation plan, such as reviewing annual compensation budgets and setting targets and corporate performance measures for the annual and long-term variable compensation plans.

Finally, the Committee specifically implements the Company's executive compensation program as it directly pertains to the Chief Executive Officer and the Company's four other most highly compensated executives, *i.e.*, the five "named executive officers."

The Committee has determined that in an environment where competition is increasing, it is essential that the Company have the ability to attract, motivate and retain high quality executives from within and outside the utility industry.

Because of the extremely competitive market for executive talent, the Personnel & Compensation Committee has adopted a compensation structure based on a blend of utility and general competitive industry markets. The structure is also flexible to allow setting salaries at pure general industry levels where that may be necessary to attract certain specific skills and experience.

Consistent with this approach, the total compensation program relies on competitive base compensation generally at or below the median of the market with annual and long-term variable compensation opportunities generally above the median of the market. This places a much greater emphasis on variable compensation that aligns executive and stockholder interests.

This total compensation philosophy is important to the success of the Company because the Company is facing increasing competition and related risks. The Company is not simply a utility anymore, but is rapidly becoming part of the general competitive industry market and, therefore, just as strategies for success must change, the compensation to drive success must also change. Prior to the merger involving Atlantic Energy and Delmarva and during 1998, this compensation philosophy enabled the Company to attract several key executives with experience and skills critical to the emerging competitive environment. These executives would not have been available under a traditional utility compensation philosophy.

Significant actions by the Committee for fiscal year 1998 included adoption of the new Conectiv executive plans (Conectiv Variable Compensation Plan, Deferred Compensation Plan, Supplemental Executive Retirement Plan [SERP], and Change In Control Agreements) and other compensation and benefit plans for Conectiv employees. The Committee also sets base compensation, annual variable targets and performance measures and long-term grants under the various executive programs, including special awards of performance accelerated stock options to the CEO and the three other named executive officers described above.

Chief Executive Officer Compensation

Mr. Cosgrove's compensation reflects Conectiv's compensation philosophy. His base compensation, annual and regular long-term variable compensation place him at total compensation levels consistent with the median level of other CEO's at similarly-sized utility and manufacturing companies represented in the Compensation Comparison Group. Additional emphasis on achieving increased stockholder value has been created with a special grant of performance accelerated stock options. This special grant will cause his long term compensation and total compensation to exceed the median targets for 1998.

Base Compensation Action

Conectiv was formed by a merger involving Delmarva and Atlantic Energy in early 1998. Mr. Cosgrove's base compensation was set during the merger process to reflect the size of Conectiv and the increasing competitive environment in which Conectiv does business. His 1998 base compensation is at the median target level developed through a comparison of other Chief Executive Officers of similarly-sized corporations using a blend of utilities and general industry. His salary for 1999 will remain the same as in 1998.

Annual Variable Compensation

To provide clear focus on increasing stockholder value through the successful completion of the merger and growing the new Conectiv businesses, Mr. Cosgrove received additional levels of long-term awards in place of an annual variable opportunity for 1997. Therefore, there is no annual variable pay for 1997 reflected in 1998 compensation.

Mr. Cosgrove's annual variable compensation target opportunity for 1998 was set at 50% of base compensation, with a minimum payout of 0% and a maximum payout of 75% of base compensation. Payment of any award requires achieving a predetermined level of 1998 earnings established by this Committee. Performance measures for 1998, predetermined by this Committee, included earnings available for common stock, cash flow return on capital employed and cash flow. Awards for 1998 for Mr. Cosgrove and the four other named executive officers have not been determined.

Long-Term Variable Compensation

Long-term incentive grants are a critical component of the Conectiv executive compensation philosophy, since they align executive interests very clearly with increased stockholder value. For 1998, Mr. Cosgrove received grants of non-qualified stock options, dividend equivalent units, performance accelerated restricted stock, and performance accelerated stock options (reflected in the Compensation Tables). The regular grants of non-qualified stock options, dividend equivalent units and performance accelerated restricted stock provided a long-term variable compensation opportunity approximately at the median of the defined competitive market.

The special, non-recurring grant of performance accelerated stock options was awarded to create additional emphasis on achieving higher levels of stockholder value. In order for Mr. Cosgrove to receive any value from this grant prior to vesting at nine and one-half years, there must be a significant increase in stockholder value. Such increases prior to nine and one-half years will result in accelerated vesting of this grant in increments of one-third. The first third would vest when stockholder value increases by $400,000,000, at which time Mr. Cosgrove's options would vest at a value of $1,200,000, or .3% of the increase in stockholder value. The entire grant would vest if stockholder value increases by $800,000,000, at which time Mr. Cosgrove's options would vest at a value of $2,400,000 or .3% of the increase in stockholder value. Only under results that yield increases in stockholder value and trigger accelerated vesting of this grant would Mr. Cosgrove's 1998 compensation exceed the median target compensation level.

Personnel & Compensation Committee

S.I. Gore, Chairperson	R.B. McGlynn
M.B. Emery	B.J. Morgan

Personnel & Compensation Committee Interlocks and Insider Participation

The Personnel & Compensation Committee is comprised solely of non-officer directors. Logical Business Solutions, which is owned by Mr. Emery's son-in-law, Paul Kleiman, had contracts with Conectiv Resource Partners, Inc., a subsidiary of the Company, with a gross value of $227,000 during 1998 for information technology consulting services. Except as described in the preceding sentence, there are no Personnel & Compensation Committee interlocks.

Summary Compensation Table

Table 1—SUMMARY COMPENSATION TABLE

Name and Principal Position	Year(1)	Annual Compensation: Annualized Salary	Annual Compensation: Variable Compensation (Bonus)(2)	Annual Compensation: Other Annual Compensation	Long-Term Compensation: Awards: Restricted Stock(5)	Long-Term Compensation: Awards: Securities Underlying Options	Long-Term Compensation: Payouts: LTIP Payouts (3)	All Other Compensation (4,6)
H.E. Cosgrove, ... Chairman of the Board and Chief Executive Officer	1998	$600,000	—	—	—	360,000	572,134	$ 12,329
M.I. Harlacher, ... President	1998	$340,000	—	—	—	—	—	$ 3,742
	1997	$224,525	$96,800	$814,696	—	—	—	$3,208,196
	1996	$215,317	$27,500	$ 8,527	$305,138	15,800	10,429	$ 7,413
B.R. Elson, ... Executive Vice President	1998	$325,000	—	—	—	170,000	21,560	$ 4,074
T.S. Shaw, ... Executive Vice President	1998	$325,000	—	—	—	170,000	155,267	$ 9,478
B.S. Graham, ... Senior Vice President	1998	$250,000	—	—	—	170,000	155,267	$ 5,308

(1) Base salary is shown as an annualized amount. Other items of compensation reflect the full calendar 1998 compensation received from Conectiv and either Delmarva or Atlantic City Electric Company.

(2) The 1998 bonus, which is an annual variable award, has not yet been determined. The target award is 50% of annualized salary for Mr. Cosgrove and 40% for Messrs. Harlacher, Elson and Shaw and Mrs. Graham.

(3) During 1998 all restrictions lapsed on the performance-based restricted stock granted in 1995 and 1996 under the Delmarva LTIP due to the merger involving Delmarva and Atlantic Energy. Under the "change in control" provisions, the awards fully vested resulting in a payout to Mr. Cosgrove of 21,160 shares (11,570 for 1995 and 9,590 for 1996) valued at $454,940; to Mr. Shaw of 5,450 shares (2,870 for 1995 and 2,580 for 1996) valued at $117,175; and to Mrs. Graham of 5,450 shares (2,870 for 1995 and 2,580 for 1996) valued at $117,175. Shares were valued at $21.50 at the time of payout. Dividends on shares of restricted stock and dividend equivalents are accrued at the same rate as that paid to all holders of Common Stock. As of December 31, 1998; Mr. Cosgrove held 45,520 shares of restricted stock (35,520 for 1997 and 10,000 for 1998) and 30,000 Dividend Equivalent Units ("DEU's"); Mr. Elson held 4,000 shares of restricted stock for 1998 and 10,000 DEU's; Mr. Shaw held 12,010 shares of restricted stock (8,010 for 1997 and 4,000 for 1998) and 10,000 DEU's; Mrs. Graham held 12,010 shares of restricted stock (8,010 for 1997 and 4,000 for 1998) and 10,000 DEU's. Holders of restricted stock are entitled to receive dividends as declared.

(4) The amount of All Other Compensation for each of the named executive officers for fiscal year 1998 include the following: Mr. Cosgrove, $2,125 in Company matching contributions to the Company's Savings and Investment Plan, $10,000 in Company matching contributions to the Company's Deferred Compensation Plan and $204 in term life insurance premiums paid by the Company; for Mr. Shaw, $2,630 in Company matching contributions to the Company's Savings and Investment Plan, $6,644 in Company matching contributions to the Company's Deferred Compensation Plan and $204 in term life insurance premiums paid by the Company; for Mrs. Graham, $2,604 in Company matching contributions to the Company's Savings and Investment Plan, $2,500 in Company matching contributions to the Company's Deferred Compensation Plan and $204 in term life insurance premiums paid by the Company; for Mr. Elson, $2,969 in Company matching contributions to the Company's Savings and Investment Plan and $1,105 in term life insurance premiums paid by the Company; and for Mr. Harlacher, $3,300 in Company matching contributions to the Company's Savings and Investment Plan and $442 in term life insurance premiums paid by the Company.

(5) Pursuant to the change-of-control provisions of Atlantic Energy's equity based long term incentive plan for executives ("EIP"), Mr. Harlacher elected to receive the cash equivalent of the restricted stock which had been awarded under the plan.

(6) The amount of All Other Compensation for Mr. Harlacher for the fiscal year ended 1997 include the following: $4,750 in Company matching contributions to the Atlantic City Electric Company 401(k) Savings and Investment Plan; $1,986 in Company matching contributions to the Atlantic City Electric Company Deferred Compensation Plan; $1,065 in term life insurance premiums paid by Atlantic City Electric Company; $996,238 in payouts under the Atlantic City Electric Company supplemental executive retirement plan; $674,340 cash payout for restricted stock awarded under the Atlantic Energy EIP which vested due to change-in-control; $1,358,817 in excess retirement benefits from the Atlantic City Electric Company Retirement Plan; $171,000 adjustment to compensate Mr. Harlacher for certain economic disadvantages associated with the payout of benefits in 1997 rather than in 1998.

Table 2 — Option Grants in Last Fiscal Year (1)

Name	Number of Securities Underlying Options Granted (#)	% of Total Options Granted to Employees in Fiscal Year	Exercise Price ($/Sh)	Expiration Date	Grant Date Present Value(4)
H.E. Cosgrove	300,000(2)	29%	$22.84375	1/2/08	$385,831
	60,000(3)	6%	$22.84375	1/2/08	$137,063
M.I. Harlacher	—	0%	—	—	—
	—	0%	—	—	—
B.R. Elson	150,000(2)	14%	$22.84375	1/2/08	$192,915
	20,000(3)	2%	$22.84375	1/2/08	$ 45,688
T.S. Shaw	150,000(2)	14%	$22.84375	1/2/08	$192,915
	20,000(3)	2%	$22.84375	1/2/08	$ 45,688
B.S. Graham	150,000(2)	14%	$22.84375	1/2/08	$192,915
	20,000(3)	2%	$22.84375	1/2/08	$ 45,688

(1) Currently, Delmarva does not grant stock appreciation rights. The options reflected in this table are for payouts in shares of Conectiv Common Stock.

(2) Denotes Performance Accelerated Stock Options ("PASO's") which were granted on a one-time basis. PASO's have a ten-year term and vest and are first exercisable 9 and 1/2 years from date of grant without regard to stock price performance. Exercise date will accelerate for favorable stock price performance (i.e., first 1/3, second 1/3 and third 1/3 of PASO's vest after stock trades at $26, $28 or $30 per share, respectively, for ten consecutive trading days). There is a minimum holding period of three years from date of grant during which these options are not exercisable.

(3) Denotes Nonqualified Stock Options. One-half of such Options vest and are exercisable at end of second year from date of grant. Second one-half vest and are exercisable at end of third year from date of grant.

(4) Determined using the Black-Scholes model, incorporating the following material assumptions and adjustments: (a) exercise price of $22.84375, equal to the Fair Market Value ("FMV") as of date of grant; (b) an option term of ten years; (c) risk-free rate of return of 6.00%; (d) volatility of 20.00%; and (e) dividend yield of 7.00%. For valuation purposes, PASO's are valued as a premium-priced stock option as of the date of grant with an exercise price of $30 on a FMV of $22.84375.

Table 3 — Aggregated Option Exercises in Last Fiscal Year and FY-End Option Values

Name	Shares Acquired on Exercise	Value Realized ($)(1)	Number of Securities Underlying Unexercised Options at FY-End(2) Exercisable/Unexercisable	Value of Unexercised In-the-MoneyOptions at FY-End(1) Exercisable/Unexercisable
H. E. Cosgrove	0	0	14,400/360,000	$51,225/$596,250
M. I. Harlacher	0	0	—	$ —
B. R. Elson	0	0	0/170,000	$ 0/$281,563
T. S. Shaw	0	0	0/170,000	$ 0/$281,563
B. S. Graham	0	0	0/170,000	$ 0/$281,563

(1) The closing price for Conectiv's common stock as reported by the New York Stock Exchange on December 31, 1998 was $24.50. Any value in the options would be based on the difference between the exercise price of the options and the value at the time of the exercise (e.g., $24.50 as of close of business on 12/31/98), which difference would be multiplied by the number of options exercised.

(2) Only 14,400 stock options of Mr. Cosgrove are currently exercisable. None of the remaining options may be exercised earlier than two years from date of grant for regular, non-performance based options and nine and one half years from date of grant for performance based options (subject to accelerated vesting for favorable stock price performance).

Table 4 — Long-Term Incentive Plans—Awards in Last Fiscal Year Name

	Number of Restricted Shares/Dividend Equivalent Units (#)(1)	Performance Period Until Maturation or Payout(2)
H. E. Cosgrove	10,000 shs/30,000 units	3/2/05
M. I. Harlacher	—	—
B. R. Elson	4,000 shs/10,000 units	3/2/05
T. S. Shaw	4,000 shs/10,000 units	3/2/05
B. S. Graham	4,000 shs/10,000 units	3/2/05

(1) In addition, Mr. Cosgrove held 35,520 performance shares (valued at $870,240) and Mr. Shaw and Mrs. Graham held 8,010 performance shares (valued at $196,245) from a 1997 award with a four year performance cycle under the Delmarva Power Long Term Incentive Plan.

(2) Awards of Restricted Shares (Performance Accelerated Restricted Stock or "PARS") and Dividend Equivalent Units ("DEU's") were made to four of the named executive officers. The payout of shares of PARS may potentially be "performance accelerated." Restrictions may lapse any time after 3 years (i.e., after March 1, 2001) upon on achievement of favorable stock price performance goals. In the absence of such favorable performance, restrictions lapse after 7 years (i.e., March 2, 2005) provided that at least a defined level of average, total return to shareholders is achieved. As of December 31, 1998, Mr. Cosgrove's 10,000 Restricted Shares were valued at $245,000 and Messrs. Elson and Shaw and Mrs. Graham's 4,000 PARS were valued at $98,000. These values for both Restricted Shares and performance shares are based on the December 31, 1998 closing stock price of $24.50. For Dividend Equivalent Units, one DEU is equal in value to the regular quarterly dividend paid on one share of Conectiv common stock. The Dividend Equivalent Units shown are payable in cash for twelve quarters over a three year period ending with the quarterly dividend equivalent payable January 31, 2001. At that point, the 1998 DEU award lapses.

Pension Plan

The Conectiv Retirement Plan includes the Cash Balance Pension Plan and grandfathered provisions relating to the Delmarva Retirement Plan and the Atlantic Retirement Plan that apply to employees who had either 20 years of service or were age 50 on the effective date of the Cash Balance Pension Plan (January 1, 1999). Certain executives whose benefits from the Conectiv Retirement Plan are limited by the application of Federal tax laws also receive benefits from the Supplemental Executive Retirement Plan.

Cash Balance Pension Plan

The named executive officers participate in the Conectiv Retirement Plan and earn benefits that generally become vested after five years of service. On an annual basis, a recordkeeping account in a participant's name is credited with an amount equal to a percentage of the participant's total pay, including base salary, overtime and bonuses, depending on the employee's age at the end of the plan year, as follows:

Age at end of Plan Year	% of Pay
Under 30	5
30 to 34	6
35 to 39	7
40 to 44	8
45 to 49	9
50 and over	10

These accounts also receive interest credits based on average U.S. Treasury Bill rates for the year. In addition, certain annuity benefits earned by participants under the former Delmarva and Atlantic Retirement Plans are fully protected as of December 31, 1998, and will be converted to an equivalent cash amount and included in each employee's initial cash balance account. When an employee terminates employment, the amount credited to his or her account is converted into an annuity or paid in a lump sum.

Supplemental Retirement Benefits

Supplemental retirement benefits are provided to certain employees, including each executive officer, whose benefits under the Conectiv Retirement Plan are limited by type of compensation or amount under applicable Federal tax laws and regulations. Designated employees may also receive an annual benefit at retirement equal to a percentage of final average compensation multiplied by years of service reduced by the amount of all benefits received under the Conectiv Retirement Plan and other nonqualified arrangements.

Estimated Retirement Benefits Payable to Named Executive Officers

The following table shows the estimated retirement benefits, including supplemental retirement benefits under the plans applicable to the named executive officers, which would be payable if he or she were to retire at normal retirement age, which is age 65, at 1998 compensation, expressed in the form of a lump sum payment. Years of service credited to each named executive officer as of his or her normal retirement date are as follows: Mr. Cosgove, 42; Ms. Graham, 30; Mr. Shaw, 40; Mr. Elson, 16 (8 of which are additional years of service for purposes of the supplemental retirement benefits), and Mr. Harlacher, 43.

Estimated Retirement Benefits

Name	Year of 65th Birthday	Lump Sum Value
H. E. Cosgrove	2008	$2,993,000(2)
B. S. Graham	2013	1,540,000(1)
T. S. Shaw	2012	1,789,000(2)
B. R. Elson	2006	1,213,000(2)
M. I. Harlacher	2007	2,323,000(2)

(1) Amounts include (i) interest credits for cash balances projected to be 5.01% per annum on annual salary credits and prior service balances, if any, and (ii) accrued benefits as of December 31, 1998 under retirement plans then applicable to the named executive officer. Benefits are not subject to any offset for Social Security payments or other offset amounts and assume no future increases in base salary or total pay.

(2) Under the Conectiv Retirement Plan's grandfather provisions, employees who participated in the Delmarva or Atlantic Retirement Plans and who met certain age and service requirements as of December 31, 1998, will have retirement benefits for all years of service up to retirement calculated according to their original final pay formula benefit. This benefit will be compared to the cash balance account and the employee will receive whichever is greater. Estimated benefits are based on the Delmarva Retirement Plan for Messrs. Cosgrove, Shaw and Elson, the Cash Balance Pension Plan for Mrs. Graham and the Atlantic Retirement Plan for Mr. Harlacher. The amount of benefit under such grandfathering is illustrated in the following tables applicable to the Delmarva and Atlantic Retirement Plans, respectively:

Delmarva Retirement Plan
PENSION PLAN TABLE
Annual Retirement Benefits in Specified Remuneration and Years of Service Classifications

Average Annual Earnings for the 5 Consecutive Years of Earnings that Result in the Highest Average	15 Yrs.	20 Yrs.	25 Yrs.	30 Yrs.	35 Yrs.
$125,000	28,599	38,132	47,665	57,198	66,732
200,000(1)	46,599	62,132	77,665	93,198	108,732
300,000(1)	70,599	94,132	117,665	141,198(2)	164,732(2)
400,000(1)	94,599	126,132	157,665(2)	189,198(2)	220,732(2)
500,000(1)	118,599	158,132(2)	197,665(2)	237,198(2)	276,732(2)

(1) Effective January 1, 1998, annual compensation recognized may not exceed $160,000.
(2) For 1998, the limit on annual benefits is $130,000.

Benefits are payable in the form of a 50% joint and surviving spouse annuity or lump sum and earnings include base salary, overtime and bonus.

Atlantic Retirement Plan PENSION PLAN TABLE
Annual Retirement Benefits in Specified Remuneration and Years of Service Classifications

Average Annual Earnings for the 5 Consecutive Years of Earnings that result in the Highest Average	15 Yrs.	20 Yrs.	25 Yrs.	30 Yrs.	35 Yrs.
$125,000	30,000	40,000	50,000	60,000	70,000
200,000(1)	48,000	64,000	80,000	96,000	112,000
300,000(1)	72,000	96,000	120,000	144,000(2)	168,000(2)
400,000(1)	96,000	128,000	160,000(2)	192,000(2)	224,000(2)
500,000(1)	120,000	160,000(2)	200,000(2)	240,000(2)	280,000(2)

(1) Effective January 1, 1998, annual compensation recognized may not exceed $160,000.
(2) For 1998, the limit on annual benefits is $130,000.

Benefits are paid in the form of a life annuity or lump sum and earnings include base salary and bonus.

Change in Control Severance Agreements And Other Provisions Relating to Possible Change in Control

Conectiv has entered into change in control severance agreements with Messrs. Cosgrove, Elson and Shaw and Mrs. Graham and two other senior executives. The agreements are intended to encourage the continued dedication of members of Conectiv's senior management team. These agreements provide potential benefits for such executives upon actual or constructive termination of employment (other than for cause) following a change in control of Conectiv, as defined in such agreements. Each affected executive would receive a severance payment equal to three times Base Salary and Bonus and Conectiv-paid medical, dental, vision, group life and disability benefits during the three years after termination of employment, and a cash payment equal to the actuarial equivalent of accrued retirement pension credits equal to 36 months of additional service.

In the event of a change in control, the Variable Compensation Plan provides that outstanding options become exercisable in full immediately, all conditions to the vesting of PARS are deemed satisfied and shares will be fully vested and nonforfeitable, DEU's will become fully vested and be immediately payable, variable compensation deferred under the Management Stock Purchase Program will be immediately distributed, and payment of variable compensation, if any, for the current year will be decided by the Board's Personnel & Compensation Committee. For the Deferred Compensation Plan, the Committee may decide to distribute all deferrals in cash immediately or continue the deferral elections of participants in which event Conectiv will fully fund a ''springing rabbi trust'' to satisfy the obligations. An independent institutional trustee will maintain any such trust established by reason of this provision.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

All shares of ACE's common stock are owned by Conectiv, ACE's parent company.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report.

1. Financial Statements—The following financial statements are contained in Item 8 of Part II.

	Page No.
Report of Independent Accountants	II-12, 13
Consolidated Statements of Income for the years ended December 31, 1998, 1997, and 1996	II-14
Consolidated Statements of Cash Flows for the years ended December 31, 1998, 1997, and 1996	II-15
Consolidated Balance Sheets as of December 31, 1998 and 1997	II-16,17
Consolidated Statements of Changes in Common Stockholder's Equity for the years ended December 31, 1998, 1997, and 1996	II-18
Notes to Consolidated Financial Statements	II-19

2. Financial Statement Schedules

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 1998, is presented below. No other financial statement schedules have been filed since the required information is not present in amounts sufficient to require submission of the schedule or because the information required is included in the respective financial statements or the notes thereto.

Schedule II—Valuation and Qualifying Accounts
Years Ended December 31, 1998, 1997, 1996
(Dollars in thousands)

	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
1998					
Allowance for doubtful accounts	$3,500	$ 5,003	—	$5,003(A)	$ 3,500
Merger-related impairment loss on assets held for sale	—	$18,000	—	—	$18,000
1997					
Allowance for doubtful accounts	$3,500	$ 3,935	—	$3,935(A)	$ 3,500
1996					
Allowance for doubtful accounts	$3,300	$ 5,359	—	$5,159(A)	$ 3,500

(A) Accounts receivable written off.

3. Schedule of Operating Statistics for the three years ended December 31, 1997 can be found on page IV-4 of this report.

4. Exhibits

Exhibit Number	
2	Amended and Restated Agreement and Plan of Merger, dated as of December 26, 1996, between DPL, Atlantic Energy, Inc., Conectiv, Inc. and DS Sub, Inc. (Filed with Registration Statement No. 333-18843)
3-A	A Restated Certificate of Incorporation of Atlantic Energy, Inc. (File No. 1-9760, Form 10-Q for quarter ended September 30, 1987—Exhibit 4(a)); Certificate of Amendment to restated Certificate of Incorporation of Atlantic Energy, Inc. dated April 15, 1992. File No. 33-53511, Form S-8 dated May 6, 1994—Exhibit No. 3(ii).
3-B	By Laws of Atlantic Energy, Inc. as amended July 13, 1995 (File No. 1-9760, Form 10-Q for the quarter ended June 30, 1995—Exhibit 3b(1).
3-C	Agreement of Merger between Atlantic City Electric Company and South Jersey Power & Light Company filed June 30, 1949, and Amendments through May 3, 1991 (File No. 2-71312—Exhibit No. 3(a); File No. 1-3559, Form 10-Q for quarter ended June 30, 1982— Exhibit No. 3(b); Form 10-Q for quarter ended March 31, 1985— Exhibit No. 3(a); Form 10-Q for quarter ended March 31, 1987—Exhibit No. 3(a): Form 8-K dated October 12, 1988—Exhibit No. 3(a); Form 10-K for fiscal year ended December 31, 1990—Exhibit No. 3c; and Form 10-Q for quarter ended September 30, 1991— Exhibit No. 3c).
3-D	Certificate of Merger of Atlantic Energy, Inc. with and into Conectiv, Inc. filed with Delaware Secretary of State, effective as of March 1, 1998, filed herewith.
3-E	Certificate of Merger of Atlantic Energy, Inc. with and into Conectiv, Inc. filed with New Jersey Department of State, effective as of March 1, 1998, filed herewith.
3-F	Certificate to change name from Conectiv, Inc., to Conectiv filed with the Delaware Secretary of State pursuant to Section 102(a) of the Delaware General Corporation Law, filed herewith.
3-G	By-Laws of Atlantic City Electric Company, as amended April 24, 1989 (File No. 1-3559, Form 10-Q for the quarter ended September 31, 1989—Exhibit No. 3).
4-A	Mortgage and Deed of Trust, dated January 15, 1937, between Atlantic City Electric Company and The Bank of New York (formerly Irving Trust Company) and Supplemental Indentures through November 1, 1994 (File No. 2-66280—Exhibit No. 2(b); File No. 1- 3559, Form 10-K for year ended December 31, 1980—Exhibit No. 4(d); Form 10-Q for quarter ended June 30, 1981—Exhibit No. 4(a); Form 10-K for year ended December 31, 1983—Exhibit No. 4(d); Form 10-Q for quarter ended March 31, 1984—Exhibit No. 4(a); Form 10-Q for quarter ended June 30, 1984—Exhibit 4(a); Form 10-Q for quarter ended September 30, 1985—Exhibit 4; Form 10-Q for quarter ended March 31, 1986—Exhibit No. 4; Form 10-K for year ended December 31, 1987—Exhibit No. 4(d); Form 10-Q for quarter ended September 30, 1989—Exhibit No. 4(a); Form 10-K for year ended December 31, 1990—Exhibit No. 4(c); File No. 33-49279—Exhibit No. 4(b); File No. 1-3559, Form 10-Q for the quarter ended September 30, 1993—Exhibits 4(a) & 4(b); Form 10-K for the year ended December 31, 1993—Exhibit 4c(i); File no. 1-3559, Form 10-Q for the quarter ended June 30, 1994-Exhibit 4(a); File No. 1-3559, Form 10-Q for the quarter ended September 30, 1994—Exhibit 4(a); Form 10-K for year ended December 31, 1994—Exhibit 4(c)(1).
4-B	Indenture dated as of March 1, 1997 between Atlantic City Electric Company and The Bank of New York filed on Form 8-K, dated March 24, 1997, File No. 1-3559—Exhibit 4(e).
4-C	Indenture Supplemental dated as of March 1, 1997 to Mortgage and Deed of Trust dated January 15, 1937 between Atlantic City Electric Company and The Bank of New York filed on Form 8-K dated March 24, 1997, File No 1-3559, Exhibit 4(b).

4-D Amended and Restated Trust Agreement, dated as of October 1, 1996, by and among Atlantic City Electric Company, as Depositor, The Bank of New York, as Property Trustee, The Bank of New York (Delaware) as Delaware Trustee and the Administrative Trustees Named Therein, (File No. 1-9760, Form 10-K for year ended December 31, 1996—Exhibit No. 4f(7)).

4-E Junior Subordinated Indenture, dated as of October 1, 1996, by and between Atlantic City Electric Company and The Bank of New York, as Trustee, (File No. 1-9760, Form 10-K for year ended December 31, 1996—Exhibit No. 4f(8)).

4-F Guarantee Agreement, dated as of October 1, 1996, by and between Atlantic City Electric Company as Guarantor, and The Bank of New York as Guarantee Trustee, (File No. 1-9760, Form 10-K for year ended December 31, 1996—Exhibit No. 4f(9)).

4-G Amended and Restated Trust Agreement, dated as of October 1, 1998, by and among Atlantic City Electric Company, as Depositor, The Bank of New York, as Property Trustee, The Bank of New York (Delaware) as Delaware Trustee and the Administrative Trustees Named Therein, filed herewith.

4-H Junior Subordinated Indenture, dated as of October 1, 1998, by and between Atlantic City Electric Company and The Bank of New York, as Trustee, filed herewith.

4-I Guarantee Agreement, dated as of October 1, 1998, by and between Atlantic City Electric Company as Guarantor, and The Bank of New York as Guarantee Trustee, filed herewith.

10-A Termination Agreement dated August 14, 1997 between Atlantic Energy, Inc. and Michael J. Chesser. (Filed with Form 10-K for the year ended December 31, 1997, File No. 1-3559).

10-B Agreement as to ownership as tenants in common of the Salem Nuclear Generating Station Units 1, 2, and 3, dated November 24, 1971, and of Supplements, dated as of September 1, 1975, and as of January 26, 1977 (File No. 2-43137—Exhibit No. 5(p); File No. 2-60966—Exhibit No. 5(m); and File No. 2-58430—Exhibit No. 5(o)).

10-C Agreement as to ownership as tenants in common of the Peach Bottom Atomic Power Station Units 2 and 3, dated November 24, 1971 and of Supplements dated as of September 1, 1975 and as of January 26, 1977 (File No. 2-43137—Exhibit No. 5(o); File No. 2-60966—Exhibit No. 5(j); File No. 2-58430—Exhibit No. 5(m)).

10-D Owners Agreement, dated April 28, 1977 between Atlantic City Electric Company and Public Service Electric & Gas Company for the Hope Creek Generating Station Units No. 1 and 2 (File No. 2-60966—Exhibit No. 5(v)).

10-E Amendment to Owners Agreement for Hope Creek Nuclear Generating Station, dated as of December 23, 1981, between Atlantic City Electric Company and Public Service Electric & Gas Company (File No. 1-3559, Form 10-K for year ended December 31, 1983—Exhibit No. 10b(3-2)).

12-A Computation of ratio of earnings to fixed charges.

12-B Computation of ratio of earnings to fixed charges and preferred dividends.

23 Consent Independent Accountants.

27 Financial Data Schedules.

(b) Reports on Form 8-K:

On December 7, 1998, ACE filed a report on Form 8-K under Item 5, Other Events, regarding proposed legislation for restructuring the electric utility industry in New Jersey.

On February 17, 1999, ACE filed a report on Form 8-K under Item 5, Other Events, regarding the New Jersey Electric Discount and Energy Competition Act.

ATLANTIC CITY ELECTRIC COMPANY

SCHEDULE OF OPERATING STATISTICS
FOR THE THREE YEARS ENDED DECEMBER 31, 1998

The table below sets forth selected financial and operating statistics for ACE's electric business for the years ended December 31, 1998, 1997, and 1996.

	1998	1997	1996
Electricity generated and purchased (MWH):			
Generated	5,499,473	4,664,548	4,775,306
Purchased	3,881,906	5,409,378	5,905,566
Interchange deliveries	(86,432)	(793,102)	(1,006,516)
Total system output for load	9,294,947	9,280,824	9,674,356
Electric sales (MWH):			
Residential	3,544,048	3,454,705	3,587,352
Commercial	3,724,853	3,538,414	3,493,694
Industrial	1,308,826	1,253,347	1,214,005
Resale	404,883	317,824	811,467
Other sales, losses and miscellaneous system uses (1)	312,337	716,534	567,838
Total disposition of energy	9,294,947	9,280,824	9,674,356
Electric operating revenue (thousands):			
Residential	$ 435,710	$ 446,917	$ 448,738
Commercial	378,777	382,812	369,364
Industrial	108,042	110,469	105,734
Resale	4,513	7,949	19,052
Miscellaneous revenues (2)	7,053	24,685	12,065
Total service territory	934,095	972,832	954,953
Interchange deliveries	69,161	23,657	27,539
Merchant revenues (3)	31,638	72,045	1,868
Total electric revenues	$1,034,894	$1,068,534	$ 984,360
Number of customers (end of period):			
Residential	429,720	425,036	420,499
Commercial	57,499	56,816	55,580
Industrial	1,003	1,023	1,013
Resale	—	—	—
Other	522	523	519
Total customers (4)	488,744	483,398	477,611

(1) Includes unbilled sales.
(2) Includes unbilled revenues and other miscellaneous revenues.
(3) Offsystem and competitive sales.
(4) Service territory only.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934 the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 26, 1999.

ATLANTIC CITY ELECTRIC COMPANY
(Registrant)

By: /s/ JOHN C. VAN RODEN
(John C. van Roden,
Senior Vice President and Chief Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated, on March 26, 1999.

Signature	Title
/s/ HOWARD E. COSGROVE **(Howard E. Cosgrove)**	Chairman of the Board and Chief Executive Officer
/s/ JOHN C. VAN RODEN **(John C. van Roden)**	Senior Vice President and Chief Financial Officer
/s/ JAMES P. LAVIN **(James P. Lavin)**	Controller and Chief Accounting Officer
/s/ MEREDITH I. HARLACHER, JR. **(Meredith I. Harlacher, Jr.)**	Director
/s/ THOMAS S. SHAW **(Thomas S. Shaw)**	Director
/s/ BARRY R. ELSON **(Barry R. Elson)**	Director
/s/ BARBARA S. GRAHAM **(Barbara S. Graham)**	Director