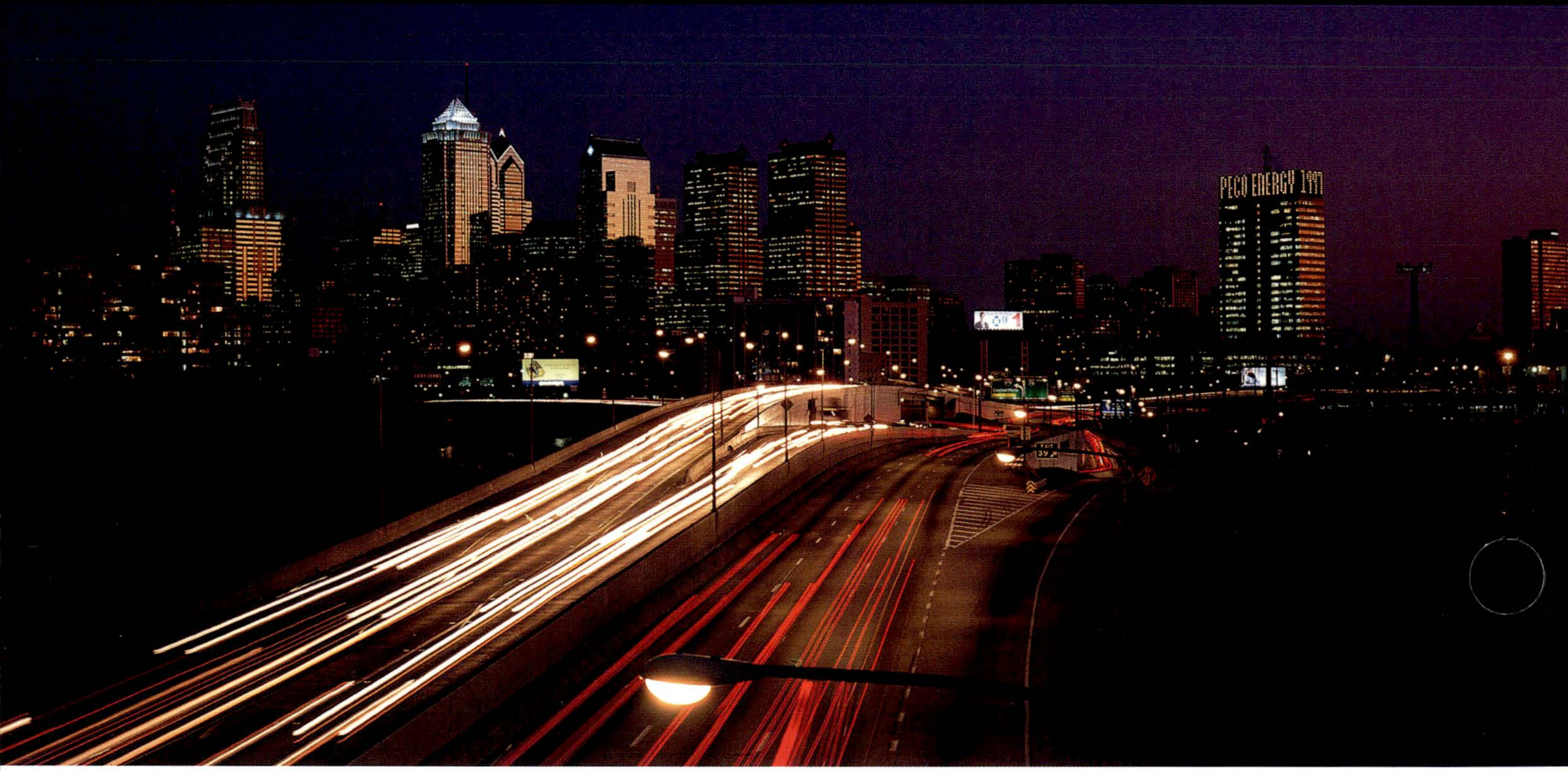
PECO ENERGY 1997 ANNUAL REPORT



FINANCIAL HIGHLIGHTS

(Thousands of Dollars)	**1997**	1996	% Change
Operating Revenues	**$4,617,901**	$4,283,650	7.8%
Operating Expenses, excluding taxes	**$3,302,179**	$2,735,603	20.7%
Taxes Charged to Operations	**$602,860**	$639,647	(5.8%)
Operating Income	**$1,005,631**	$1,248,501	(19.5%)
Extraordinary Item (Net of taxes)	**($1,833,664)**	—	—
Earnings Applicable to Common Stock (After extraordinary item)	**($1,513,910)**	$499,169	(403.3%)
Earnings Applicable to Common Stock (Before extraordinary item)	**$319,754**	$499,169	(35.9%)
Earnings per Average Common Share *(Dollars)* (After extraordinary item)	**($6.80)**	$2.24	(403.6%)
Cash Dividends Paid per Common Share *(Dollars)*	**$1.80**	$1.755	2.6%
Average Shares of Common Stock Outstanding *(Thousands)*	**222,543**	222,490	—
Construction Expenditures	**$490,200**	$548,854	(10.7%)
Common Shareholders' Equity	**$2,726,731**	$4,645,981	(41.3%)
Book Value Per Average Common Share *(Dollars)*	**$12.25**	$20.88	(41.3%)

This Annual Report contains forward-looking statements which should be read in conjunction with the cautionary statement on forward-looking statements located on page 20.

Fellow Shareholders:

Nineteen-ninety-seven was a tumultuous year for PECO Energy. It was a year that opened with the uncertainty of electric competition and restructuring in Pennsylvania, grew to one of great expectations of a fair transition to competition, but ended with the great disappointment of an onerous restructuring rate order.

During the year, there was much promise of an early resolution of the issues related to Pennsylvania's Electricity Generation Customer Choice and Competition Act. Over the summer, we worked in cooperation with other parties, some of whom had previously opposed our positions, to structure a settlement which we felt was fair to both our customers and our shareholders. But at the end of the year, the Pennsylvania Public Utility Commission voted, by a bare majority, to adopt a much more onerous plan. This action led to the dramatic financial write-off and dividend reduction announced in January of this year.

In facing these difficult decisions, I believe both management and the Board of Directors took the appropriate steps for the long-term interests of you, the investor. We have appealed the Commission's actions in both Commonwealth and federal courts, but continue to move quickly to position PECO Energy to be successful in the new competitive environment being created by a myriad of state and federal regulatory actions and pending legislation.

PECO Energy's 1997 financial results were dominated by the Commission actions that transpired during the year. The Company reported a net loss of $1.5 billion or $6.80 per share. This loss was primarily due to an extraordinary charge before taxes of $3.1 billion, or $8.24 per share after taxes, to reflect the effects of the Commission's order in the Company's restructuring proceeding, along with several one-time charges totaling $214 million before taxes, or $0.56 per share after taxes. Earnings per share for 1997, excluding the above items, were $2.00 versus $2.24 in 1996.

The decision to reduce the dividend was a difficult one, but I firmly believe it was the prudent thing to do. The one dollar per share dividend level will give us the flexibility we need to deal with the demands of competition while carrying out our non-regulated growth strategy. We feel the new dividend level is sustainable.

There is little doubt that the most significant event of last year was the Company's restructuring proceeding before the Commission. We felt strongly that the interests of both customers and shareholders would best be served by reaching a settlement instead of enduring protracted litigation.

In August, we announced a settlement agreement with a group of intervenors. The settlement included, among other things, the recovery of $5.461 billion in stranded assets and costs; an agreement by the Company to write off $2 billion of additional stranded assets and costs; the transfer of generating assets and operations to a separate entity; and the voluntary reduction by the Company of the phase-in period to full customer choice of generation supplier from three years to two. In addition, the settlement would have provided all of our customers an average ten percent rate reduction beginning September 1998.

In December 1997, however, the Commission, in a 3-2 vote, rejected the settlement agreement and adopted its own radical plan. The Commission reduced our stranded cost recovery to under $5 billion, reduced the return allowed on stranded costs, provided no guaranteed rate reductions for customers and ordered that the transition to competition be accelerated.

Because of the adverse effect the Commission's decision would have on the Company, we filed appeals in both the Commonwealth Court of Pennsylvania and in U.S. District Court. Avoiding litigation was a primary factor leading to the settlement agreement; however, the Commission's action left us with no alternative.

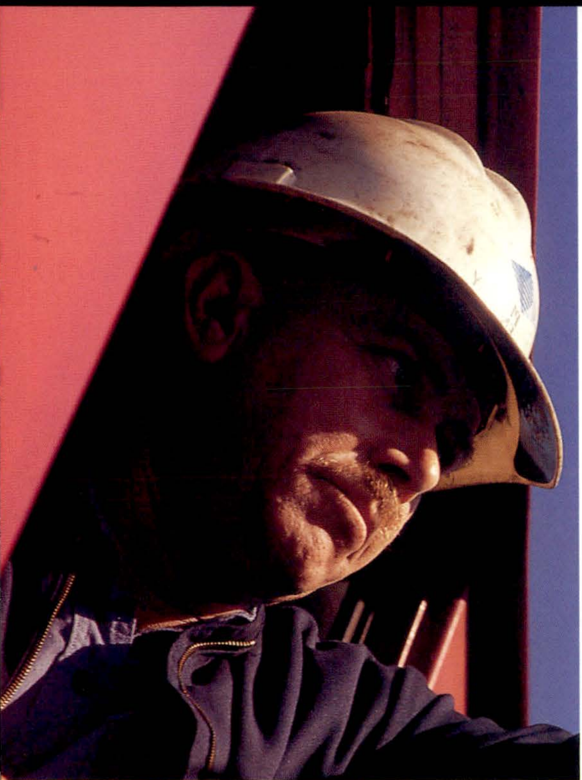
The Company took numerous actions last year to put us in a strong competitive position for the future. In September, we announced the formation of AmerGen Energy Company, LLC, a joint venture with British Energy of Edinburgh, Scotland. AmerGen's mission is to pursue opportunities to acquire and operate nuclear generating stations in the U.S. AmerGen is backed with the recognized expertise of both PECO Energy and British Energy in operating nuclear power plants. This strategy is designed to position PECO Energy as one of the nation's major electric generating companies.

Our expertise in operating and maintaining nuclear plants is also being recognized, as evidenced by our agreement with Northeast Utilities to manage the return to service of two units at the Millstone, Connecticut, nuclear power plant and our three-year contract with Illinois Power to manage the restart and operation of its Clinton nuclear power station.

Last summer, we launched EnergyOne with Utilicorp United of Kansas City, Missouri, with the aim of developing a national energy brand. PECO Energy is an equity partner with Utilicorp and the first EnergyOne franchisee.

PECO Energy Company

The company whose new strategic architecture will move it to the forefront of the business of energy.



Company Profile

Incorporated in Pennsylvania in 1929, PECO Energy Company provides retail electric and natural gas service in southeastern Pennsylvania and, through pilot programs, natural gas service to areas in Maryland and New Jersey. The Company also engages in the wholesale marketing of electricity on a national basis and participates in joint ventures which provide telecommunication services in the Philadelphia area.

PECO Energy's traditional retail service territory covers 2,107 square miles. Electric service is furnished to an area of 1,972 square miles with a population of about 3.6 million, including 1.6 million in the City of Philadelphia. Approximately 94% of the retail electric service area and 64% of retail kilowatthour sales are in the suburbs around Philadelphia, and 6% of the retail service area and 36% of such sales are in the City of Philadelphia. Natural gas service is supplied in a 1,475-square-mile area of southeastern Pennsylvania adjacent to Philadelphia with a population of 1.9 million.

Through Horizon Energy, a wholly owned subsidiary of the Company, and PECO Energy/EnergyOne, a franchised energy products brand, PECO Energy participates in Pennsylvania's electric competition pilot program.

Strategic Architecture

The year 1997 brought with it a tremendous change in Pennsylvania's electric utility industry. For the first time, although initially through limited pilot programs, Pennsylvania's retail electric customers have the opportunity to choose their generation suppliers. After a phase-in period beginning in 1999, all Pennsylvania electricity customers will have this opportunity.

Knowing that the industry would soon be in turmoil with marketers from every corner of the nation wanting a piece of the deregulated energy pie, the Company began to look for other means to secure revenues and increase shareholder value.

To this end, the Company reviewed its strategy and developed a new strategic architecture. Keeping in mind what it does best — operating generating facilities, constructing reliable power-delivery systems and marketing electric power — PECO Energy has ventured beyond the traditional bounds of the industry, yet has not strayed from its core competencies.

This annual report describes this strategic architecture and some of the innovative measures the Company is taking to enhance shareholder value.

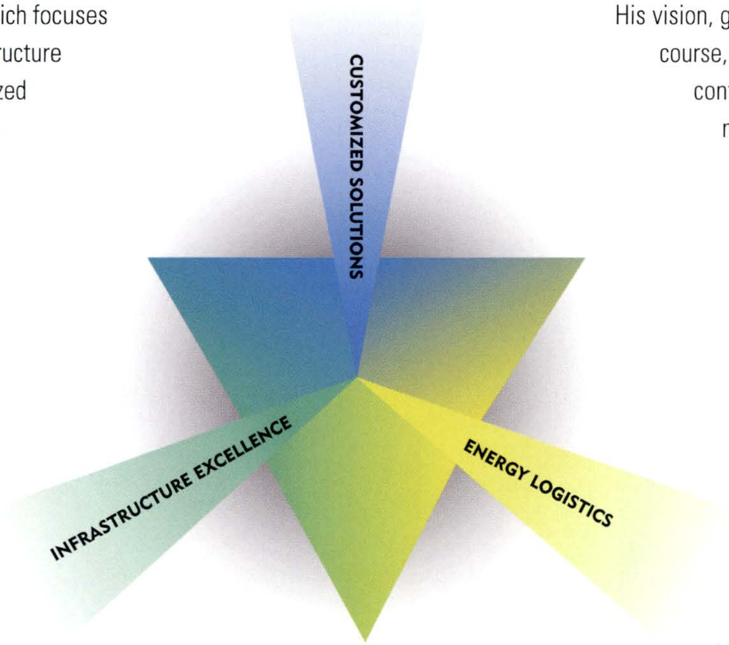
In November, we signed an agreement with the Massachusetts Health and Education Facilities Authority to provide more than one billion kilowatthours annually to its 462-member organization and 130,000 employees. We believe that this type of agreement could serve as a blueprint in the new, competitive power marketplace.

Throughout the year we took these and other actions to implement our strategic architecture, which focuses on our core competencies of infrastructure excellence, energy logistics and customized solutions. This strategy is aimed at adding shareholder value through future growth opportunities.

Building upon our core competencies of infrastructure excellence, we will grow our generation business. Our ability to successfully manage energy logistics, demonstrated by the rapid expansion of the Company's Power Team into 47 states, gives us many value-added opportunities. From these two core competencies we built the third — customized solutions — to enable us to provide our customers with the solutions that best suit their energy needs.

You'll read more about our strategic architecture, what it means today and in the future, in this annual report.

The Company benefits from the guidance and counsel of a qualified and involved Board of Directors. In June 1997, Daniel L. Cooper, a retired vice admiral in the U.S. Navy and retired vice president and general manager of the Nuclear Services Division of Gilbert/Commonwealth, Inc., joined the Board.



The three rays of the Company's Strategic Architecture represent the paths that PECO Energy will take in order to compete in the competitive marketplace. Infrastructure Excellence, the world class operation and maintenance of facilities, and Energy Logistics, the informational and physical aspects of buying, selling and delivering energy products and services, are two of PECO Energy's core competencies — that is, the things it does best. Customized Solutions — delivering to customers the specific services that meet customers' needs — grew from these core competencies.

This year also marks the retirement of three dedicated members of your Board — Joseph J. McLaughlin, Richard G. Gilmore and James A. Hagen. We thank them for their long years of service to our Company.

Another change in the Board occurred last summer when Joe Paquette retired as chairman. For more than four decades he committed himself to the success of PECO Energy. His vision, guidance and leadership set our course, and we are pleased that he continues to serve as a valuable member of your Board.

There were also several significant senior management changes last year. Michael J. Egan was named Senior Vice President of Finance and Chief Financial Officer, Kenneth G. Lawrence became Senior Vice President of the Local Distribution Company, Gregory A. Cucchi was named Senior Vice President of Ventures and William H. Smith, III became Senior Vice President of Business Services.

These are, indeed, challenging times. While we are confronting changes in our industry unlike any we have seen before, we are taking the actions that are difficult but necessary to successfully compete in the future. I strongly believe that PECO Energy will emerge from this period of transition as a strong competitor — a national company with global opportunities. With your continued support, I am confident we can overcome the challenges, seize the opportunities before us and continue to add value to your investment.

Corbin A. McNeill, Jr.,
PECO Energy Chairman, President and Chief Executive Officer
February 2, 1998

PECO Energy has clearly demonstrated its world-class capabilities in infrastructure excellence, which grew out of the processes developed over several years at the Company's Peach Bottom and Limerick nuclear generating stations.

"Infrastructure excellence is really what PECO Nuclear is all about," said Dickinson Smith, PECO Energy's Chief Nuclear Officer. "We're world class managers of nuclear power plants, evidenced by our ability to put systems in place that can operate nuclear plants safely and efficiently."

AmerGen, a joint venture with British Energy, combines the core competencies of PECO Energy and British Energy. AmerGen is evaluating nuclear plants for acquisition and will bring its collective best practices and proven work processes to improve the safety and efficiency of acquired plants.

"AmerGen will combine the shared values and cultures of PECO Energy and British Energy and transplant them into the acquired plants as a complete package," said Smith.

Another example of infrastructure excellence is the Company's joint venture with AT&T Wireless Services. The ability of PECO Energy's Power Delivery and Telecommunications groups to install Personal Communications System (PCS) equipment atop the Company's existing towers and buildings was a major contribution to this venture.

"PECO Energy was the first utility AT&T worked with in building a PCS network and we were very impressed by its skills and project management," said Daniel R. Hesse, CEO and President of AT&T Wireless.

Another venture, based on the Company's extensive fiber optic network, became the backbone of a new telecommunications system providing services to medium and large businesses. PECO Hyperion Telecommunications, a joint venture between PECO Energy and Hyperion Telecommunications of Pennsylvania, a subsidiary of Adelphia Cable Company, will provide a lower-cost local link to a subscriber's long distance carrier.

Exelon Corporation, a subsidiary of PECO Energy, operates the cogeneration facility on the site of the former USX Fairless Plant in Bucks County, Pennsylvania, and provides operating and maintenance services to the gas and electric distribution systems for that site. These opportunities arose, in part, from the Company's Vision Quest program, which reduced costs while improving on-time delivery and reliability at its fossil and hydro-electric plants.

The Company's new Distributed Network Management program will take the work management philosophy developed at PECO Nuclear and apply it to power delivery services offered to smaller entities.

"Under this venture, we take the infrastructure excellence skills from nuclear, combine them with those of power delivery and provide them to network managers through a performance contract to operate and maintain their systems," said Greg Cucchi, Senior Vice President of Ventures. "This will become more and more attractive as the industry deregulates and managers come under increased pressure to operate their systems efficiently."

Most recently, on January 5, 1998, Illinois Power Company of Decatur, Illinois, chose PECO Nuclear to manage its Clinton nuclear plant, shut down by the Nuclear Regulatory Commission in September 1997. Under the three-year contract, which may be renewed for an additional five years, a core group of PECO Nuclear employees will provide management expertise to Illinois Power.

In the future, as PECO Energy further develops and enhances its expertise in infrastructure excellence, the Company will expand geographically and bring its capabilities to an increasing number of customers.

Above. PECO Hyperion, the join venture between PECO Energy and Hyperion Telecommunications, will provide to medium and large business customers a lower-cost link to long distance phone service. Here, a PECO Hyperion technician adjusts fiberoptic cables at the PECO Hyperion central operations center.

Right. At the Millstone nuclear generating facility in Connecticut, operated by Northeast Utilities, PECO Nuclear is working with Millstone plant personnel to return Millstone to commercial operation. PECO Nuclear brings to Millstone successful system and processes to fa[illegible]e the restart and operati[illegible] plant. Pictured, a P[illegible]ergy engineer and a Northeast Utilities manager review blueprints of Millstone Unit No. 3.

The ray of PECO Energy's strategic architecture that focuses on the Company's ability to efficiently operate and maintain facilities. Traditionally, this has meant electric generating plants. By developing and enhancing this core competency, the Company will extend its reach by marketing its world-class capabilities to business and commercial customers.

Beginning in late 1995, the three units at Millstone Nuclear Station in Connecticut, operated by Northeast Utilities (NU), were shut down due to numerous problems associated with the units.

[illegible]xecutives realized that, in [illegible]eturn the units to co[illegible]rcial operation, NU must demonstrate to the NRC that NU is able to effectively operate the facility. NU contracted with PECO Nuclear to provide core management support for the restart of Millstone Unit No. 1.

PECO Nuclear was chosen due to its experience in returning its Peach Bottom station to service after an NRC-ordered shutdown. Peach Bottom is now recognized as an industry leader in safe, reliable operations.

A group of PECO Nuclear employees, led by John McElwain, PECO Energy's Vice President of Nuclear Projects, was assigned to Millstone to implement PECO Nuclear's work management processes.

According to McElwain, "One of the major concerns with the Millstone restart activities was the lack of acceptance of responsibility for the work to be done. It was our job to reverse this attitude."

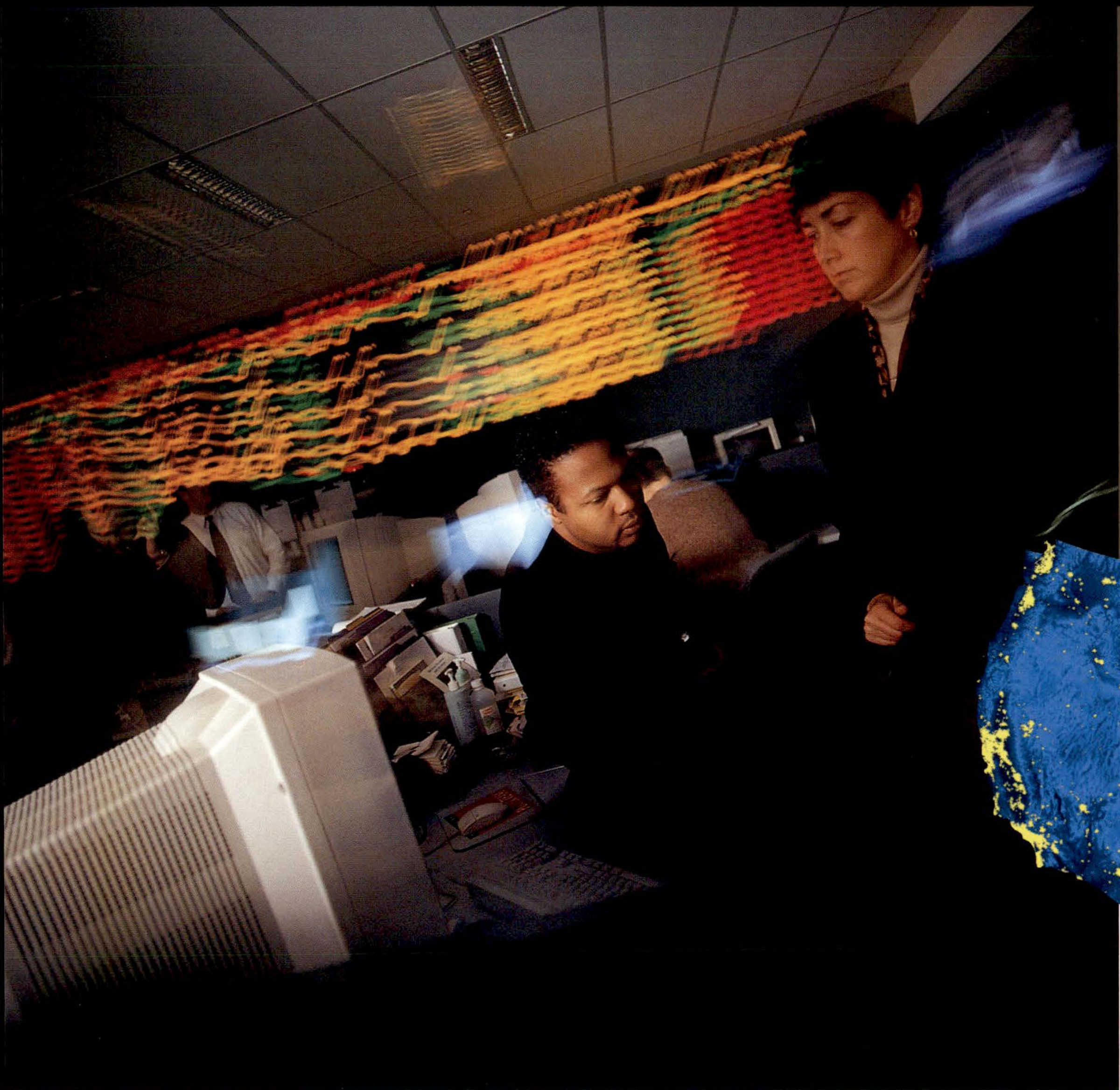
Recognizing PECO Nuclear's strength in infrastructure excellence, NU approached the Company about not only returning Millstone to commercial operation, but also how NU could adopt PECO Nuclear's philosophies.

"What PECO Nuclear is selling is operational excellence," said PECO Nuclear's Dickinson Smith. "We feel capable of entering almost any situation and delivering a safe, cost-effective and workable solution."

PECO Energy's role at Millstone has recently been expanded. It is now assisting with the restart operations at Unit No. 3.

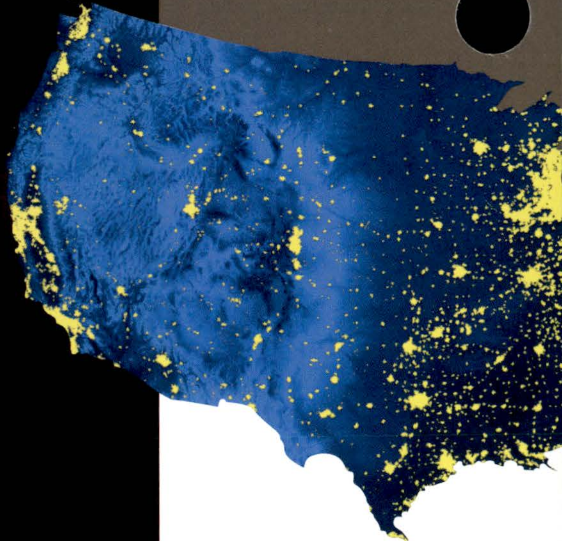
Energy Logistics

The ray of PECO Energy's strategic architecture that provides energy to anyone, anytime, anywhere. By focusing on providing electricity, natural gas and other services to business and industry, the Company strengthens its position as an industry leader.



Left. The Company's Power Team is considered the largest real-time deliverer of electricity in the United States. In order to be successful in this business, it is necessary to have all the systems in place to complete transactions smoothly and quickly, sometimes in as little as 15-minute segments and for thousands of transactions a day. Here, two of Power Team's marketers view on-line, real-time national energy prices before completing a transaction.

Below. A nighttime satellite view of the United States. Through Power Team, PECO Energy is helping to meet the nation's growing energy needs.



Nancy Bessey knows how energy logistics, a core competency of PECO Energy, has helped make Power Team, which she leads, so successful.

Power Team's strong position is enhanced by PECO Energy's generating capacity, located in the middle of the Northeast Corridor. By using this generating capacity and its access to transmission, Power Team is exceptionally reliable and is not just a go-between in transactions.

"We have developed a culture that clearly distinguishes us from the other players," she says. "That culture really builds on the foundation of PECO Energy, which is 'we deliver a highly reliable product.' We built on this foundation of responsibility, reliability and service orientation that started with PECO Energy."

Power Team is viewed as a unique entity in the national power-marketing business, building a large supply business while maintaining integrity of product delivery.

"This is a supply and demand business," Bessey said. "So, the more supply we can obtain and market, the stronger the cash flow for the Company."

In order to succeed in this business, it is necessary to have all the systems in place to complete thousands of transactions each day smoothly and quickly.

"We have the advantage of having been building our system for quite some time," Bessey said. "Before anybody even thought about an open market for electricity, we were already allocating resources to systems development. We were marketers before marketing was cool."

Power Team's goal is to be at the top of the list of power marketers in the country. Currently, it is considered the largest national real-time deliverer of electricity.

Another major strength of Power Team is its employees. "The o[illegible] thing we can really be proud [illegible] that we don't have the trader turnover that a lot of our competitors have," Bessey noted. "That's because our people know we are here for the long haul; they see success here and they realize that this success is going to continue."

Expertise in energy logistics enables the Company to efficiently manage the complex informational and physical aspects of buying, selling and delivering energy products and services so that these services can be used by customers anytime, anywhere.

With ample reliable generation and a location in the center of the Northeast Corridor, PECO Energy began with a strong position in energy logistics and was able to easily begin moving supply to other areas.

"We started with a competitive supply," said Nancy Bessey, the Company's Vice President of Power Transactions and President of Power Team. "From there we simply started expanding. Our competitors were in a more difficult position. If they didn't have direct access to competitive power, they had to go out and buy it."

Since beginning operations in 1994, the growth of the Company's wholesale power-marketing business has made the Company's Power Team one of the top power marketers in the U.S.

For now, Power Team sells electricity to wholesale purchasers — primarily utilities — and helps to serve the load in PECO Energy's traditional service territory. As the Company expands its sources of electric generation through acquisitions, partnerships and marketing agreements, its power-marketing business will explore the option of adding natural gas to its marketing portfolio.

As deregulation of electric generation accelerates, PECO Energy is poised to pursue retail sales directly to large power users, such as large industrial customers and national commercial accounts.

This type of business-to-business energy service will be the gateway to new customers. This is a key mission of the Ventures Group, the Company's business unit formed to seek out energy-related opportunities in emerging markets.

The focus will be on large commercial and industrial customers and large load aggregators such as electric co-operatives, municipalities and other utilities. Also targeted are national accounts like fast-food chains and national retailers; regional accounts, such as supermarket chains; and state and federal governments. In addition, the Company expects to gain access to retail customers outside of its traditional service territory through agreements with power resellers.

A key element of energy logistics is energy supply, which concentrates on the marketing of electricity, gas and other fuels for customers.

Power Team recently entered into an agreement with Tenaska, Inc., of Omaha, Nebraska, to market the output of an 800-megawatt, natural gas-fired merchant power plant to be developed, financed, constructed, owned and operated by Tenaska. Upon completion, scheduled for the year 2000, the plant will be the largest merchant power plant in the U.S.

"The strategy is to build upon the portfolio of assets we have," said Bessey. "Everybody else in this business seems to be talking about consolidation or merger. Based upon our firsthand knowledge of the market, we will acquire access to energy to serve the demand where it exists."

PECO Energy is building on its core competencies of infrastructure excellence and energy logistics to provide customers with specific targeted services that meet their needs.

In June 1997, the Company announced it would offer a variety of services, previously available only on an individual basis, to industrial and commercial customers under its customized energy solutions program. The aim of the program is to provide larger customers with a single point of contact for energy products and services. The diverse offerings range from traditional utility services to those not associated with the generation of electricity.

Traditional utility areas such as plant operations and gas delivery have led to the design and development of on-site programs for customers' generation needs, management of their fuel supplies and general oversight of their power-related operations and maintenance.

Based on its broad experience in providing energy, the Company also provides customers with information on economic development and relocation services, as well as information as diverse as specialized financing, information systems and management services.

For example, the owners of C.P. Yeatman & Sons, a 240-acre mushroom farm, wanted to spend less of their time on fuel handling in the pasteurization and growing processes and more time on its basic business — raising mushrooms. They came to PECO Energy looking for a solution.

"PECO Energy understands our business," said Tim Hahn, Yeatman's controller, corporate secretary and treasurer.

The Company converted Yeatman's 80-horsepower portable steam boiler into a dual-fuel boiler that can use either oil or gas. The boiler generates steam needed to kill bacteria and mold and to facilitate compost pasteurization. Yeatman also converted three oil-fired, hot-water boilers used for temperature control.

"PECO Energy came up with the idea for applying this technology to our boilers and made sure the project went smoothly," Hahn said.

PECO Energy is focused on helping its customers be competitive in their marketplaces by building strong relationships. With customized energy solutions, PECO Energy can focus on what it does best and customers can focus on what they do best.

For instance, based on the Company's buying and handling capabilities, Exelon Corporation obtained a contract with the City of Vineland, New Jersey, to supply its coal. Exelon provides Vineland with a fully integrated fuel management system, including the purchase of 20,000 tons of coal annually, as well as storage, handling and transportation. Vineland uses the coal to provide electricity to homes and businesses in the city.

The ray of PECO Energy's strategic architecture that focuses on solving problems to address the needs of targeted customers. The Company will continue to look for ways to benefit these customers' operations.

Above. Greg Cucchi, PECO Energy Senior Vice President of Ventures (left) and Robert Ciolek, Executive Director of the Massachusetts Health and Education Facilities Authority, after signing one of the nation's largest long-term power sales agreements. As a result of the agreement, PECO Energy will provide lower-cost electricity to more than 460 Massachusetts health and education agencies, as well as to their 130,000 employees.

Left. Inside the CoreStates Center, new home of the National Hockey League's *Philadelphia Flyers* and the National Basketball Association's *Philadelphia 76ers*. PECO Energy became the CoreStates Center's energy partner by introducing the concept of thermal ice storage, an innovative electro-technology that would efficiently satisfy the complex's heating and cooling needs. The goal of the partnership is to make the CoreStates Center, and the adjacent CoreStates Spectrum, the most cost-effective facilities of their kind.

In November 1997, PECO Energy signed an agreement with the Massachusetts Health and Education Facilities Authority (HEFA) which could serve as a blueprint in the emerging market for competitive po

se of the Company's pr abilities to manage plants and efficiently move power, it was possible to develop a customized energy solution which met HEFA's needs.

The Company will provide more than one billion kilowatthours annually to HEFA's 462-member organization and its 130,000 employees.

HEFA's power-buying consortium is the largest in New England and one of the largest in the country. PECO Energy won the contract in a competition with 27 other companies who responded to HEFA's request for proposal.

"Our contract with HEFA heralds our entry into retail markets outside of Pennsylvania," said Greg Cucchi, PECO Energy's Senior Vice President of Ventures.

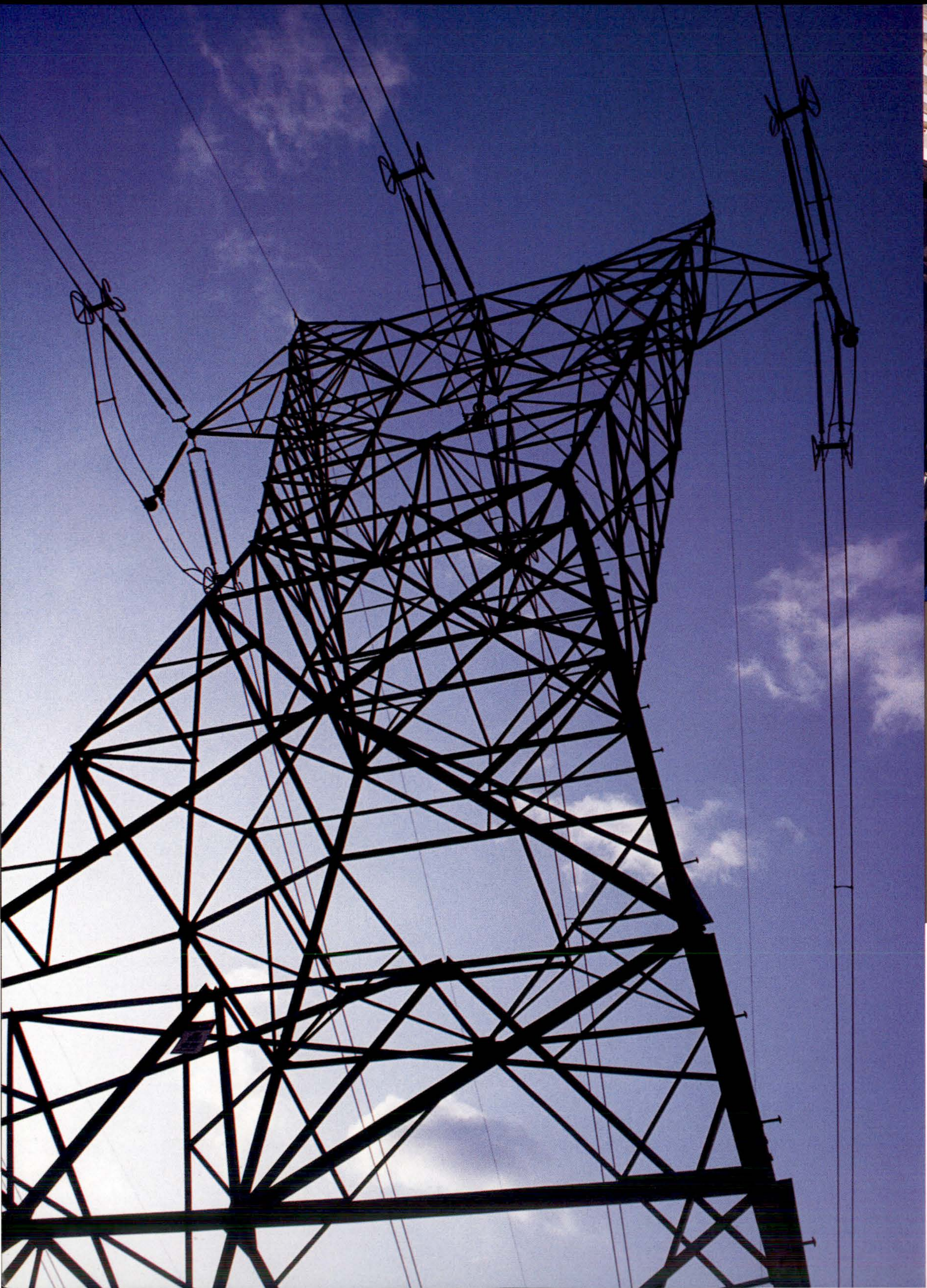
Anticipating expected savings of between 10 and 20 percent, HEFA's members expressed satisfaction with the PECO Energy contract.

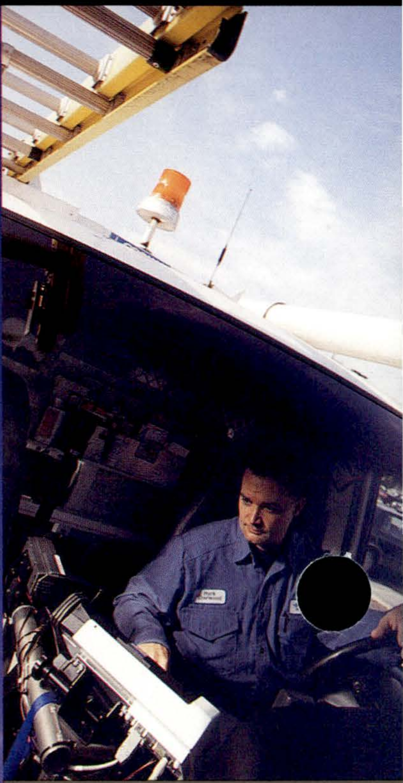
Warren Young, director of engineering services for the Boston Museum of Fine Arts, told *The Wall Street Journal*, "We spend a little over one million dollars a year on electricity. It's a significant part of our operating budget. You can do a lot of programs with that extra $100,000 minimum and $200,000 on the upside."

The Wall Street Journal also noted that many critics of deregulation claim that "individuals would be the last in line to benefit from competition because they'd be too small for power marketers to bother with. But the authority's agreement with PECO (which includes 130,000 employees of member organizations) enables the small customers to benefit by being part of the large buying group."

Local Distribution Company

The unit of PECO Energy Company charged with delivering to customers energy services and products in a safe, reliable and cost-effective fashion.





Above. An Energy Technician in PECO Energy's Field Services organization meets customer needs by using mobile data terminals linked to a mobile radio system. The two-way radio service for voice dispatch and mobile data applications supports field operations essential to the safe and reliable delivery of PECO Energy products and services. Energy Technicians are able to receive and complete orders from their vehicles, eliminating the need to report to a service building for work orders.

While PECO Energy's strategic architecture will help the Company grow into a national company with global opportunities, it remains critically important for the Company's future success that it operate a safe, efficient and cost-effective Local Distribution Company (LDC) in Southeastern Pennsylvania.

Kenneth G. Lawrence, PECO Energy's Senior Vice President of the LDC, said the mission of the LDC is to provide high-quality energy services to customers. Doing this will help to enhance shareholder value as the LDC assumes responsibility for more than $3 billion in revenue for PECO Energy.

"When most people in the Greater Philadelphia area think of PECO Energy what they will be thinking of is the LDC," Lawrence said. "Our highest priority is to focus on the customer. We want to make sure our high levels of service and reliability are continued as we enter a customer choice environment, and that customers are pleased with the quality of service they receive from PECO Energy. Additionally, the LDC will work to assure that customers will be able to move more smoothly into the new competitive marketplace."

The Company formed the LDC in 1997 as a separate business unit and will continue to shape it through 1998.

"The year 1998 will really be one of integration, reinvention and repositioning of the LDC. Beginning in 1998 and continuing into the year 2000, PECO Energy and the LDC will focus on the continued transition of the business to competition," Lawrence said.

Beyond that, the LDC plans to assist customers with new and improved applications for electric and gas use, while keeping its sights on enhancing shareholder value. The LDC's key roles in the transition to customer choice have already been defined by the Pennsylvania Public Utility Commission. It is charged with the responsibility of providing reliable service to customers, and is designated as the default supplier for those customers who do not select an alternative electricity supplier. Its responsibility will be to secure competitively priced electric supplies for those customers who do not elect to change.

"Just because we have been designated as the deliverer of electric and gas energy to customers, we cannot rest on our laurels," said Lawrence. "We must continue to maintain our existing infrastructure and improve our level of service in order to continue to provide reliable energy services to our customers. I believe we are up to that challenge."

PECO Energy is committed to providing high-quality, value-added services to customers in its traditional service territory. To enhance its ability to provide such services, the Company entered into a partnership with UtiliCorp United of Kansas City, Missouri, and formed EnergyOne. The goal of EnergyOne is to create the industry's first nationwide, branded energy marketing company that will enable its franchisees to provide customers with one-stop shopping for a variety of products and services. Local electric utilities, the EnergyOne franchised distributors, will provide to customers a single invoice and point-of-payment for a full range of services.

In order to build a strong national b[illegible]me, EnergyOne sought out s[illegible], whose products were nat[illegible]lly known and respected. EnergyOne contracted with companies such as AT&T for telecommunications services; ADT for home and business security and environmental monitoring services; AT&T Solutions to establish and manage EnergyOne's integrated call center services; and Itron for advanced metering and communications technology.

Adding to its strong stable of suppliers, EnergyOne recently entered into a strategic alliance with Saville Systems, a leading provider of convergent billing solutions for the telecommunications industry. This alliance will provide the first integrated billing system for utility services in the U.S. market. PECO Energy/EnergyOne, the distributor of EnergyOne products in the Company's traditional service territory, will be the first EnergyOne franchisee to use the system, as part of Pennsylvania's electric competition pilot program.

"[illegible]h EnergyOne, we're able to g[illegible] front of the marketplace," sa[illegible]O Energy Chairman Corbin McNeill. "And, we can do this without the risks and costs of going it alone, while being among the leaders in a new business category — integrated utility services."

"We can give utilities the ability to be immediately competitive," said Andy Guarriello, CEO of EnergyOne.

It is anticipated that EnergyOne will serve more than 30 million customers nationwide over the next three to five years, while providing three major benefits for PECO Energy.

First, it will provide a branding strategy to compete with national brand entities in PECO Energy's traditional service territory. Second, it will establish a national distribution channel for products that PECO Energy develops. And third, it will provide an opportunity to earn revenues from other utilities who join EnergyOne as franchisees.

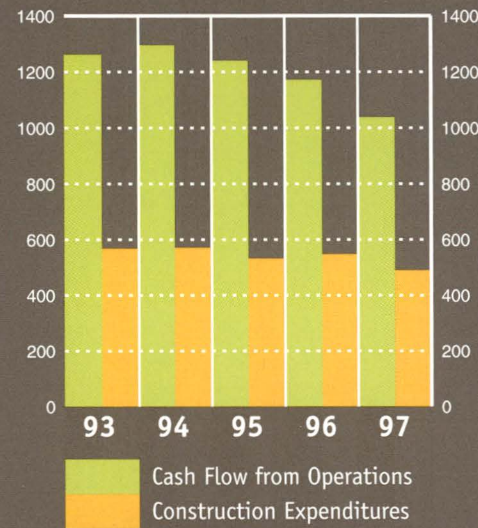
PECO Energy Performance

EARNINGS* AND DIVIDENDS

dollars per share

CASH FLOW FROM OPERATIONS AND CONSTRUCTION EXPENDITURES

millions of dollars

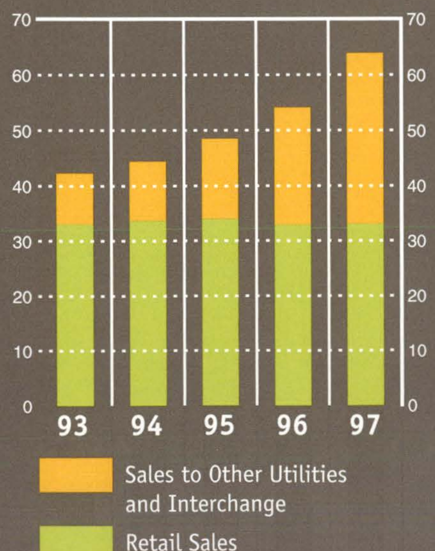


TOTAL DEBT AND INTEREST CHARGES

millions of dollars

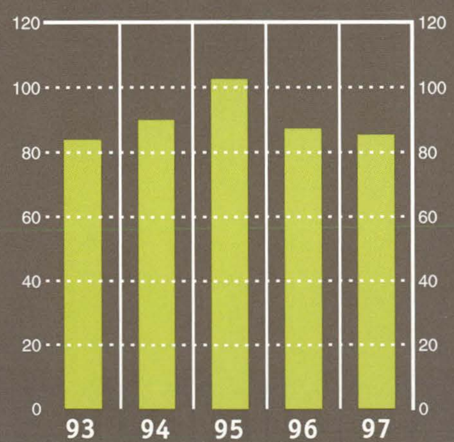
TOTAL ELECTRIC SALES

billions of kilowatthours



GAS SALES AND TRANSPORTED GAS

billions of cubic feet



POWER TEAM GEOGRAPHIC REACH AND WHOLESALE CUSTOMERS

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

General

In December 1996, Pennsylvania Governor Ridge signed into law the Electricity Generation Customer Choice and Competition Act (Competition Act) which provides for the restructuring of the electric utility industry in Pennsylvania, including retail competition for generation beginning in 1999.

Pursuant to the Competition Act, in April 1997, the Company filed with the Pennsylvania Public Utility Commission (PUC) a comprehensive restructuring plan detailing its proposal to implement full customer choice of electric generation supplier. The Company's restructuring plan identified $7.5 billion of stranded costs (the loss in value of the Company's electric generation-related assets which will result from competition). In August 1997, the Company and various intervenors in the Company's restructuring proceeding filed with the PUC a Joint Petition for Partial Settlement (Pennsylvania Plan).

In December 1997, the PUC rejected the Pennsylvania Plan and entered an Opinion and Order, revised in January 1998 (PUC Restructuring Order), that deregulates the Company's electric generation operations. The PUC Restructuring Order authorizes the Company to recover stranded costs of $4.9 billion on a discounted basis, or $5.3 billion on a book value basis, over 8½ years beginning in 1999. In January 1998, the Company filed appeals of the PUC Restructuring Order with the U.S. District Court for the Eastern District of Pennsylvania (Eastern District Court) and the Commonwealth Court of Pennsylvania (Commonwealth Court).

The Company believes that the PUC Restructuring Order provides sufficient details regarding the deregulation of the Company's electric generation operations to require the Company to discontinue the use of regulatory accounting in its financial statements for those operations. The Company determined that at December 31, 1997, $5.8 billion of its $7.1 billion of electric generation assets were impaired and it had $2.6 billion of other electric generation-related regulatory assets. Effective December 31, 1997, the Company recorded an extraordinary charge against income of $3.1 billion ($1.8 billion net of income taxes) to reflect the amount of such electric generation-related assets which will not be recovered from customers either prior to the commencement of competition or under the PUC Restructuring Order. For additional information regarding the extraordinary charge, see note 4 of Notes to Consolidated Financial Statements.

On January 26, 1998, the Company's Board of Directors reduced the quarterly common stock dividend from $0.45 per share to $0.25 per share, effective with the dividend payable on March 31, 1998. The Board of Directors concluded that, given the impact of the PUC Restructuring Order, the dividend reduction was necessary to provide the Company with the financial flexibility needed to meet the demands of competition. Although the Company cannot predict the ultimate effect of the PUC Restructuring Order and competition for electric generation services, the Company believes that its future financial condition and results of operations will be adversely affected. See "Outlook-PUC Restructuring Order."

Discussion of Operating Results

Earnings

The Company recorded a loss per common share of $6.80 in 1997 as compared with earnings per share of $2.24 and $2.64 in 1996 and 1995, respectively. The loss in 1997 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 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 normal plant additions. These decreases were partially offset by a one-time $0.18 per share recognition of income resulting from the settlement of litigation arising from the current outage of Salem Generating Station (Salem); by $0.08 per share for operational efficiencies; and by higher revenues net of fuel of $0.06 per share primarily due to increased sales to other utilities.

The $0.40 per share decrease in 1996 earnings was primarily due to higher Salem outage-related replacement power and maintenance costs which reduced earnings by $0.27 per share. Earnings also decreased by $0.18 per share in 1996 due to lower electric revenues resulting from milder weather conditions compared to 1995; by $0.12 per share due to the gain recognized in 1995 on the sale of Conowingo Power Company (COPCO); by $0.11 per share due to higher customer expenses; and by $0.10 per share due to the increased depreciation of assets associated with Limerick. These decreases were partially offset by $0.18 per share due to the Company's continuing cost control initiatives; by $0.09 per share due to savings resulting from the Company's ongoing debt and preferred stock refunding and refinancing program; and by $0.08 per share due to higher revenues resulting from increased sales to other utilities.

Significant Operating Items

Revenue and Expense Items as a Percentage of Total Operating Revenues — Percentage Dollar Changes

1995	1996	1997		1997-1996	1996-1995
90%	90%	90%	Electric	8%	2%
10%	10%	10%	Gas	5%	4%
100%	**100%**	**100%**	**Total Operating Revenues**	**8%**	**2%**
18%	23%	28%	Fuel and Energy Interchange	33%	27%
30%	30%	31%	Operation and Maintenance	12%	2%
11%	11%	12%	Depreciation	19%	7%
8%	7%	7%	Taxes Other Than Income	4%	(5%)
67%	**71%**	**78%**	**Total Operating Expenses**	**19%**	**9%**
33%	**29%**	**22%**	**Operating Income**	**(19%)**	**(11%)**
(11%)	(10%)	(9%)	Interest Expense	(2%)	(8%)
(9%)	(9%)	(8%)	Total Other Income and Deductions	4%	(9%)
24%	20%	14%	Income Before Taxes and Extraordinary Item	(27%)	(18%)
10%	8%	6%	Income Taxes	(14%)	(21%)
14%	12%	8%	Income Before Extraordinary Item	(35%)	(15%)

Operating Revenues

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 volume resulting from milder weather conditions in 1997. This increase was partially offset by reduced sales to interruptible customers switching to transportation service.

Total operating revenues increased in 1996 by $98 million to $4,284 million. This represented an $80 million increase in electric revenues and an $18 million increase in gas revenues over 1995. The increase in electric revenues was primarily due to increased sales to other utilities, partially offset by decreased retail sales due to milder weather conditions. The increase in gas revenues was primarily due to increased sales to retail customers from colder weather conditions in the first half of 1996 and higher levels of firm sales resulting from customers switching from transportation service to firm service. These increases were partially offset by decreased sales and transportation revenues resulting from unusually mild weather in December 1996.

Increases/(decreases) in electric sales and operating revenues by class of customer for 1997 compared to 1996 and 1996 compared to 1995 are set forth as follows:

	1997 - 1996		1996 - 1995	
	Electric Sales *(Millions of kWh)*	Electric Revenues *(Millions of $)*	Electric Sales *(Millions of kWh)*	Electric Revenues *(Millions of $)*
Residential	(48)	$ (1)	(86)	$ (14)
House Heating	(217)	(12)	121	5
Small Commercial and Industrial	194	30	291	19
Large Commercial and Industrial	(174)	(21)	(555)	(37)
Other	(61)	8	42	3
Unbilled	397	45	(862)	(69)
Service Territory	**91**	**49**	**(1,049)**	**(93)**
Interchange Sales	992	33	439	9
Sales to Other Utilities	8,650	230	6,202	164
Total	**9,733**	**$ 312**	**5,592**	**$ 80**

Fuel and Energy Interchange Expense

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

Fuel and energy interchange expense increased in 1996 by $210 million to $973 million. The increase was primarily due to purchases needed for increased sales to other utilities, increased replacement power costs resulting from the shutdown of Salem and a net credit to expense in 1995 from certain energy sales to other utilities. Fuel and energy interchange expense as a percentage of operating revenues increased from 18% to 23% principally due to increased replacement power costs resulting from the shutdown of Salem.

Operating and Maintenance Expense

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 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 Company's ongoing cost-control efforts.

Operating and maintenance expense increased in 1996 by $23 million to $1,274 million due to higher customer expenses, higher contractor costs and higher nuclear generating station charges resulting from the shutdown of Salem. 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 Expense

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.

Depreciation expense increased in 1997 by $92 million to $581 million. The increase was primarily due to increased depreciation of assets associated with Limerick. Depreciation expense also increased due to additions to plant in service.

Depreciation expense increased in 1996 by $32 million to $489 million. The increase was primarily due to increased depreciation of assets associated with Limerick. Depreciation expense also increased due to additions to plant in service.

Interest Charges

Interest charges decreased in 1997 by $7 million to $402 million. The decrease was primarily due to the Company's ongoing 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 Monthly Income Preferred Securities (MIPS) in the third quarter of 1997. MIPS are recorded in the financial statements as Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership.

Interest charges decreased in 1996 by $36 million to $409 million. The decrease was primarily due to the Company's ongoing program to reduce and/or refinance higher-cost, long-term debt. This decrease was partially offset by the replacement of $78 million of preferred stock with MIPS in the fourth quarter of 1995.

Other Income and Deductions

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. The increase was partially offset by losses from the Company's new non-utility ventures. Also offsetting the increase was the write-off of one of the Company's telecommunications investments as a result of the circumstances involved in the Federal Communication Commission's auctioning of the personal communications systems "C-block" licenses.

Other income and deductions excluding interest charges decreased in 1996 by $60 million to a net deduction of $2 million. The decrease was primarily due to the gain recognized in 1995 on the sale of COPCO.

Income Taxes

Income taxes on operating and non-operating income decreased in 1997 by $47 million to $293 million. The decrease was primarily due to lower operating income. The decrease was partially offset by reduced tax depreciation benefits from plant and regulatory assets which are not fully normalized for ratemaking purposes.

Income taxes decreased in 1996 by $92 million to $340 million. The decrease was primarily due to lower operating income and the gain recognized in 1995 on the sale of COPCO.

Preferred Stock Dividends

Preferred stock dividends decreased in 1997 by $1 million to $17 million. The decrease was primarily due to the replacement of $62 million of preferred stock with MIPS in the third quarter of 1997.

Preferred stock dividends decreased in 1996 by $5 million to $18 million. The decrease was primarily due to the replacement of $78 million of preferred stock with MIPS in the fourth quarter of 1995.

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 generally 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.

In 1997, 1996 and 1995, internally generated cash exceeded the Company's capital requirements and dividend payments. The Company anticipates that it will be able to meet its capital requirements with internally generated cash from utility operations in 1998. Beginning in 1999, the Company expects that internally generated cash will be reduced due to price pressures resulting from competition for electric generation services and the effects of the PUC Restructuring Order. In anticipation of this expected reduction of internally generated cash, in January 1998, the Board of Directors voted to reduce the Company's common stock dividend, effective with the first quarter 1998 dividend. Based upon the 222.5 million shares of common stock currently outstanding, the common stock dividend reduction will reduce the Company's cash requirements by $178 million per year. Absent increases in the market price of electric generation services, the Company expects that internally generated cash will be further reduced in 2007, when the Company completes the recovery of its allowed stranded costs from customers. The magnitude of the reduction of internally generated cash will be affected by a number of factors, including how quickly electric generation competition develops, the Company's ability to compete, the impact of additional cost-cutting initiatives, future market prices of electric generation and the outcome of the Company's appeals of the PUC Restructuring Order.

The Competition Act authorizes the securitization of the recovery of allowed stranded costs. Under the Competition Act, securitization proceeds must be used principally to reduce qualified stranded costs and related capitalization. Unless extended by the PUC, the Company has authorization until May 22, 1998 to securitize $1.1 billion of stranded costs. It is unlikely that the Company will securitize the recovery of its stranded costs until the appeals of the PUC Restructuring Order are resolved. If the Company does securitize, it cannot predict the level of stranded cost recovery that it would be permitted to securitize or the impact of such securitization on the Company's capitalization.

At December 31, 1997, the Company's capital structure consisted of 36.8% common equity; 7.9% preferred stock and Company obligated mandatorily redeemable preferred securities (which comprised 4.8% of the Company's total capitalization structure); and 55.3% long-term debt.

The Company expects its level of net capital investment to decrease in future years. Total capital expenditures, primarily for utility plant, were $573 million in 1997 and are estimated to be $600 million in 1998. Due to the expected adverse impact of the PUC Restructuring Order and competition for electric generating services on its future capital resources, the Company is currently evaluating its capital commitments for 1999 and beyond. Certain facilities under construction and to be constructed may require permits and licenses which the Company has no assurance will be granted.

The Company's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws.

The Company has undertaken a number of new ventures, principally through its Telecommunications Group, some of which require significant cash commitments. For 1998, the Company's expected capital expenditures include approximately $150 million in such ventures.

Cash flows from operations were $1,038 million in 1997 as compared to $1,172 million in 1996 and $1,240 million in 1995. Cash flows consist of earnings, non-cash charges of depreciation and deferred income taxes.

Cash flows used in investing activities were $573 million in 1997 as compared to $663 million in 1996 and $465 million in 1995. Expenditures under the Company's construction program decreased in 1997. The Company has also made significant investments in diversified activities and other obligations. Net funds used in these activities in 1997 were $83 million, consisting of $26 million for telecommunications ventures, $54 million for nuclear plant decommissioning trust funds and $3 million for other deposits and ventures. In 1996 and 1995, funds used in similar activities were $114 million and $82 million, respectively. 1995 cash flows benefited from the sale of COPCO.

Cash flows used in financing activities were $461 million in 1997 as compared to $501 million in 1996 and $802 million in 1995. The decreases in 1997 and 1996 were primarily due to less available cash permitting fewer retirements of higher-cost debt.

The Company meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under an unsecured credit facility with a group of banks. The Company had $402 million of short-term debt, including $314 million of commercial paper, outstanding at December 31, 1997.

At December 31, 1997, the Company's embedded cost of debt was 6.9% with 12.0% of the Company's long-term debt having floating rates. As a result of the extraordinary charge in December 1997, the Company does not expect to meet the earnings test under the Company's mortgage required for the issuance of additional bonds against property additions for the twelve months ended December 31, 1998. As of December 31, 1997, the Company was entitled to issue approximately $3.6 billion of mortgage bonds without regard to the earnings test against previously retired mortgage bonds. As a result of the extraordinary charge, the Company also does not expect to meet the coverage test under Company's Articles of Incorporation required for the issuance of additional preferred stock for the twelve months ended December 31, 1998.

The Company cannot predict whether the Competition Act or the PUC Restructuring Order will ultimately affect the Company's credit ratings.

Outlook

The Company is entering a period of financial uncertainty with the deregulation of its electric generation operations in which revenues from regulated rates will be replaced by revenues from the competitive sale of electric generation at market prices. 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 assist it in the increasingly competitive electric generation environment. These advantages include the ability to produce electricity at a low marginal-cost, a high reserve margin and the demonstrated ability to efficiently operate its electric generation facilities.

The Company's future financial condition and results of operations are substantially dependent upon the effects of the Competition Act and the PUC Restructuring Order. Additional factors that affect the Company's financial condition and results of operations include operation of nuclear generating facilities, sales to other utilities, accounting issues, inflation, weather and compliance with environmental regulations.

Another factor affecting the Company's future financial condition is its ability to develop its investments in new ventures into profitable enterprises.

PUC Restructuring Order

The Competition Act was enacted in December 1996, providing for the restructuring of the electric utility industry in Pennsylvania, including retail competition for generation beginning in 1999. The Competition Act requires the unbundling of electric services into separate generation, transmission and distribution services with open retail competition for generation. Electric distribution and transmission services will remain regulated by the PUC. The Competition Act requires utilities to submit to the PUC restructuring plans, including their quantification of stranded costs which will result from competition. The Competition Act authorizes the recovery of stranded costs through charges to distribution customers for up to nine years (or for an alternative period determined by the PUC for good cause shown). During that period, the utility is subject to a rate cap which provides that total charges to customers cannot exceed rates in place as of December 31, 1996, subject to certain exceptions. The Competition Act also caps transmission and distribution rates from December 31, 1996 through June 30, 2001, subject to certain exceptions.

Pursuant to the Competition Act, in April 1997, the Company filed with the PUC a comprehensive restructuring plan. In December 1997, the PUC adopted its own restructuring plan which deregulates the Company's electric generation operations and allows the Company to recover stranded costs of $4.9 billion on a discounted basis, or $5.3 billion on a book value basis, over 8 1/2 years beginning in 1999. Recovery of allowed stranded costs will be through a separate charge to be levelized over the recovery period using a 7.47% cost of capital. Other major provisions of the PUC Restructuring Order include capping customer bills at the year-end 1996 system-wide average of 9.95 cents per kWh; beginning January 1, 1999, unbundling rates into a transmission and distribution component, the charge for recovery of stranded costs and a "shopping credit" for generation; and phasing-in customer choice of electric generation supplier for all customers in three steps, one-third of the peak load of each customer class on January 1, 1999, one-third on January 2, 1999 (one day later) and the remainder on January 2, 2000. To encourage competition, the PUC established the "shopping credit" for generation in excess of current market prices.

On January 21, 1998, the Company filed a complaint in the Eastern District Court seeking injunctive and monetary relief on the grounds that the Competition Act and the PUC Restructuring Order: (1) are preempted by Section 201(b) of the Federal Power Act; (2) effect a taking of private property without just compensation in violation of the Fifth and Fourteenth Amendments to the U.S. Constitution; (3) violate the Due Process Clause, the Contract Clause and the First Amendment of the U.S. Constitution; and (4) deprive the Company of certain other federally protected rights.

On January 22, 1998, the Company filed two Petitions for Review in the Commonwealth Court, appealing the PUC Restructuring Order. The petitions state that the PUC Restructuring Order must be set aside because it is based upon errors of law, is not supported by substantial evidence, constitutes an arbitrary and capricious abuse of administrative discretion and deprives the Company of the due process of law, to which it is entitled under Article I of the Pennsylvania Constitution.

Uncertainties of Electric Generation Restructuring

Competition in wholesale and retail electric generation is expected to create new uncertainties in the utility industry. These uncertainties include future prices of electricity in both the retail and wholesale markets, potential changes in the Company's sales portfolio and supply and demand volatility.

The Company expects that deregulation of the Company's electric generating operations will result in price pressures that will reduce the Company's future revenues. While the Company cannot predict the ultimate impact of the PUC Restructuring Order on customer bills, the PUC estimates that customers will save up to 15% of their total electric bill beginning in 1999 through June 30, 2007 and will save 30% of their total electric bill thereafter.

Competition is also expected to affect the ultimate composition of the Company's electricity sales. The "shopping credit" established by the PUC encourages electric retail customers to choose a supplier. The Company cannot predict how successful its affiliated generation marketers will be in competing for these customers and customers elsewhere in Pennsylvania. To the extent that the Company loses retail customers, it will be compelled to sell generation previously used to serve retail customers in the wholesale market. Since margins in the wholesale market are currently lower than in the retail market, this could adversely affect the Company's profit margins.

The Company is a low marginal-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 marginal-cost power plants.

The Company enters into commitments to buy and sell power. Currently, these commitments make the Company a net power purchaser. Since the price and supply volatility of electricity generation cannot be predicted at this time, the Company's position as a net purchaser exposes it to risk to the extent that it has entered into contracts that may require the Company to pay prices for purchased power in excess of market prices.

The Company, as the local distribution provider, is obligated under the PUC Restructuring Order to serve as the electric generation supplier of last resort in its service territory. This obligation will include all customers who do not elect to choose an electricity supplier as well as all customers who seek a new energy supplier but are unable to reach a service agreement with another supplier. The Company's rates are capped at 1996 levels. If energy prices rise above that level, the Company would still be obligated to serve these customers at the capped rate.

Other Competitive Initiatives

During 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888 which requires public utilities to file open-access transmission tariffs for wholesale transmission services in accordance with non-discriminatory terms and conditions established by the FERC.

In response to Order No. 888, in December 1996, the Company and the other members of PJM Interconnection, L.L.C. (PJM) filed a joint compliance filing with the FERC proposing to restructure PJM. In November 1997, the FERC issued an order which allows for the establishment of an Independent System Operator to operate the day-to-day operations of PJM. Transmission service is on a pool-wide, open-access basis using the transmission facilities of the eight historical PJM companies with a flat rate based on the costs of the transmission system where the point of delivery is located (thus there are eight rates). By January 1, 2003, PJM is required to have in place a uniform system-wide transmission rate.

The Company received approval from the FERC to remove the existing cost-based cap on prices charged for power purchased by the Company in anticipation of later resale in the wholesale market and certain changes regarding the terms of the buy-for-resale agreements. The new tariff provisions allow the Company to purchase and re-sell energy at market-based rates both within PJM and outside PJM.

The gas industry is continuing to undergo structural changes in response to FERC policies designed to increase competition. FERC policies have required interstate gas pipelines to unbundle their gas sales service from other regulated tariff services, such as transportation and storage. In anticipation of these changes, the Company has modified its gas purchasing arrangements to enable the purchase of gas and transportation at lower cost. The Company, through Horizon Energy Company, a wholly owned subsidiary, has successfully participated in pilot programs outside the Company's gas service territory to market natural gas and other services.

There is an initiative in the Pennsylvania legislature to deregulate the gas industry, which has the support of Governor Ridge. The Company cannot predict whether the Pennsylvania legislature will enact legislation that deregulates the gas industry or whether Governor Ridge 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.

As a result of competitive pressures, the Company has continued to negotiate long-term contracts with many of its larger-volume industrial customers. Although these agreements have generally resulted in reduced margins, they have permitted the Company to retain these customers.

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 approximately 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 1997, Company-operated nuclear plants operated at a 90% weighted-average capacity factor and Company-owned nuclear plants operated at a 73% weighted-average capacity factor. Company-owned nuclear plants produced 39% of the Company's electricity, despite the shutdown of the Salem units. Nuclear generation is the most cost-effective way for the Company to meet customer needs and commitments for sales to other utilities.

Public Service Electric and Gas Company (PSE&G), the operator of Salem Units No. 1 and No. 2, which are 42.59% owned by the Company, removed the units from service in the second quarter of 1995. PSE&G informed the NRC at that time that it had determined to keep the Salem units shut down pending review and resolution of certain equipment and management issues and NRC agreement that each unit is sufficiently prepared to restart. Unit No. 2 returned to service on August 30, 1997 and Unit No. 1 is expected to return to service late in the first quarter of 1998. The Company expects to incur and expense at least $20 million in 1998 for increased costs related to the shutdown. As of December 31, 1997, 1996 and 1995, the Company had incurred and expensed $152, $149 and $50 million, respectively, for replacement power and maintenance costs related to the shutdown of Salem. See note 5 of Notes to Consolidated Financial Statements.

Sales to Other Utilities

The Company's electric utility operations include the wholesale marketing of electricity. At December 31, 1997, the Company had long-term commitments relating to the purchase from unaffiliated utilities and others, energy associated with 1,330 megawatts (MW) of capacity in 1998, with 2,540 MW of capacity during the period 1999 through 2002 and with 2,430 MW of capacity thereafter. These purchases will be utilized through a combination of sales to jurisdictional customers, long-term sales to other utilities and open-market sales. Under some of these contracts, the Company may purchase, at its option, additional power as needed. The Company's future results of operations are dependent in part on its ability to successfully market the rest of this generation. See note 5 of Notes to Consolidated Financial Statements.

In the wholesale market, the Company has increased its sales to other utilities, but increased competition has reduced the Company's profit margins on these sales. At December 31, 1997, the Company had entered into long-term agreements with unaffiliated utilities to sell energy associated with 4,280 MW of capacity, of which 540 MW of these agreements are for 1998, 1,700 MW are for 1999 through 2002 and the remaining 2,040 MW extend through 2022.

Accounting Issues

Effective December 31, 1997, the Company discontinued accounting for its electric generation operations in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." For further information, see note 4 of Notes to Consolidated Financial Statements. The Company believes that its electric transmission and distribution system and gas operations continue to meet the provisions of SFAS No. 71. The Company believes that it is probable that regulatory assets associated with these operations will be recovered.

In 1997, the Financial Accounting Standards Board (FASB) issued SFAS No. 130, "Reporting Comprehensive Income," to establish standards for reporting and display of comprehensive income and its components in financial statements. The new standard requires an entity to classify items of other comprehensive income by their nature in a financial statement and to display the accumulated balance of other comprehensive income separately from retained earnings and additional paid-in capital in the equity section of a statement of financial position. The new standard is effective for fiscal years beginning after December 15, 1997. The Company will adopt SFAS No. 130 in 1998. Adoption of SFAS No. 130 will not affect the Company's financial condition or results of operations. The Company is evaluating the impact on its disclosures, but does not expect SFAS No. 130 to materially change its disclosures.

In 1997, the FASB issued SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information," to establish standards for reporting information about operating segments in annual financial statements and to require reporting of selected information about operating segments in interim financial reports issued to shareholders. It also establishes standards for related disclosures about products and services, geographical areas and major customers. The new standard is effective for fiscal years beginning after December 31, 1997. Adoption of SFAS No. 131 will not affect the Company's financial condition or results of operations. The Company is evaluating the impact on its operating segment disclosures.

During 1996, the FASB issued the Exposure Draft "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." The FASB has expanded the scope of the project to include closure or removal liabilities that are incurred at any time in 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. Until such time that the final Statement is issued, the Company will be unable to determine what, if any, effect this issue might have on its financial condition or results of operations. See note 5 of Notes to Consolidated Financial Statements.

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 cap imposed by the Competition Act, the elimination of the Energy Cost Adjustment and expected price pressures due to competition, the Company may have limited opportunity to pass the costs of inflation through to customers.

The Year 2000 Issue is the result of computer programs being written using two digits rather than four to define the applicable year and other programming techniques which 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, among other things, a temporary inability to process transactions, send bills or operate electric generation stations.

The Company has determined that it will be required to modify or replace significant portions of its software so that its computer systems will properly utilize dates beyond December 31, 1999. The Company presently believes that, with modifications to existing software and conversions to new software, the Year 2000 Issue can be mitigated. However, if such modifications and conversions are not made, or are not completed timely, the Year 2000 Issue could have a material adverse impact on the operations and financial condition of the Company. The costs associated with this potential impact are speculative and not presently quantifiable.

The Company initiated formal communications with all of its significant suppliers in March 1997 to determine the extent to which the Company is vulnerable to the suppliers' failure to remediate their own Year 2000 issue. The Company's estimated total Year 2000 project costs include the estimated costs and time associated with the impact of Year 2000 issues of third parties and are based on presently available information. There can be no guarantee that the systems of other companies on which the Company's systems rely will be timely converted, or that a failure to convert by another company, or a conversion that is incompatible with the Company's systems, would not have a material adverse impact on the Company.

The Company will utilize both internal and external resources to reprogram, or replace, and test software and computer systems for Year 2000 modifications. Management believes that adequate resources are being devoted to the Year 2000 Issue. The Company plans to complete the Year 2000 project not later than June 1, 1999. To date, the Company has funded the Year 2000 project from current operating cash flows as a base level of activity for the preliminary efforts in connection with its Year 2000 assessment and remediation plan. The Company expects the remaining costs of the Year 2000 project to be approximately $25 million.

The costs of the project and the date on which the Company plans to complete the Year 2000 modifications are based on Management's best estimates, which were derived utilizing numerous assumptions of future events including the continued availability of certain resources, third-party modification plans and other factors. However, there can be no guarantee that these estimates will be achieved; actual results could differ materially from those plans. Specific factors that might cause such material differences include, but are not limited to, the availability and cost of personnel trained in this area, the ability to locate and correct all relevant computer programs and microprocessors, and similar uncertainties.

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 27 sites where former manufactured gas plant (MGP) activities have or may have resulted in 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 two sites. Six other sites are currently under some degree of active study and/or remediation.

As of December 31, 1997 and 1996, the Company had accrued $63 and $28 million, respectively, for environmental investigation and remediation costs, including $35 and $16 million, respectively, for MGP investigation and remediation that currently can be reasonably estimated. The Company expects to expend $5 million for environmental remediation activities in 1998. The Company cannot currently 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 notes 3, 4 and 5 of Notes to Consolidated Financial Statements.

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 notes 3, 4 and 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
PECO Energy Company:

We have audited the accompanying consolidated balance sheets of PECO Energy Company and Subsidiary Companies as of December 31, 1997 and 1996, and the related consolidated statements of income, cash flows, and changes in common shareholders' equity and preferred stock for each of the three years in the period ended December 31, 1997. These financial statements are the responsibility of the Companies' management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of PECO Energy Company and Subsidiary Companies as of December 31, 1997 and 1996, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1997, in conformity with generally accepted accounting principles.

Coopers & Lybrand L.L.P.

2400 Eleven Penn Center

Philadelphia, Pennsylvania

February 2, 1998

Consolidated Statements of Income

For the Years Ended December 31,	1997	1996	1995
			Thousands of Dollars
Operating Revenues			
Electric	**$ 4,166,669**	$ 3,854,836	$ 3,775,326
Gas	**451,232**	428,814	410,830
Total Operating Revenues	**4,617,901**	4,283,650	4,186,156
Operating Expenses			
Fuel and Energy Interchange	**1,290,164**	972,380	762,762
Operating and Maintenance	**1,431,420**	1,274,222	1,251,273
Depreciation	**580,595**	489,001	457,254
Taxes Other Than Income	**310,091**	299,546	314,071
Total Operating Expenses	**3,612,270**	3,035,149	2,785,360
Operating Income	**1,005,631**	1,248,501	1,400,796
Other Income and Deductions			
Interest Expense	**(372,857)**	(382,443)	(423,711)
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership, which holds Solely Subordinated Debentures of the Company	**(28,990)**	(26,723)	(20,987)
Allowance for Funds Used During Construction	**21,771**	19,947	27,050
Settlement of Salem Litigation	**69,800**	—	—
Gain on Sale of Subsidiary	—	—	58,745
Other, net	**(66,028)**	(1,976)	(444)
Total Other Income and Deductions	**(376,304)**	(391,195)	(359,347)
Income Before Income Taxes and Extraordinary Item	**629,327**	857,306	1,041,449
Income Taxes	**292,769**	340,101	431,717
Income Before Extraordinary Item	**336,558**	517,205	609,732
Extraordinary Item (net of $1,290,961 income taxes)	**(1,833,664)**	—	—
Net (Loss) Income	**(1,497,106)**	517,205	609,732
Preferred Stock Dividends	**16,804**	18,036	23,217
Earnings Applicable to Common Stock	**$ (1,513,910)**	$ 499,169	$ 586,515
Average Shares of Common Stock Outstanding *(Thousands)*	**222,543**	222,490	221,859
Basic and Dilutive Earnings per Average Common Share Before Extraordinary Item *(Dollars)*	**$ 1.44**	$ 2.24	$ 2.64
Extraordinary Item *(Dollars)*	**$ (8.24)**	$ —	$ —
Basic and Dilutive Earnings per Average Common Share *(Dollars)*	**$ (6.80)**	$ 2.24	$ 2.64
Dividends per Common Share *(Dollars)*	**$ 1.80**	$ 1.755	$ 1.65

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the Years Ended December 31,	1997	1996	1995
			Thousands of Dollars
Cash Flows from Operating Activities			
Net Income	$ (1,497,106)	$ 517,205	$ 609,732
Extraordinary Item (net of $1,290,961 income taxes)	(1,833,664)	—	—
Income Before Extraordinary Item	336,558	517,205	609,732
Adjustments to reconcile Net Income to Net Cash provided by Operating Activities:			
Depreciation and Amortization	664,294	566,412	531,299
Deferred Income Taxes	(17,228)	166,771	183,514
Salem Litigation Settlement	69,800	—	—
Gain on Sale of Subsidiary	—	—	(58,745)
Deferred Energy Costs	(5,652)	(66,151)	(71,104)
Amortization of Leased Property	39,100	31,400	42,900
Changes in Working Capital:			
Accounts Receivable	(289,610)	53,681	(8,198)
Inventories	28,628	(2,729)	(10,872)
Accounts Payable	93,881	(86,765)	(4,686)
Other Current Assets and Liabilities	58,539	(25,040)	9,641
Deferred Credits - Other	78,846	(4,609)	5,172
Other Items affecting Operations	(19,005)	22,070	11,683
Net Cash Flows from Operating Activities	1,038,151	1,172,245	1,240,336
Cash Flows from Investing Activities			
Investment in Plant	(490,200)	(548,854)	(532,614)
Proceeds from Sale of Subsidiary	—	—	150,000
Increase in Other Investments	(83,261)	(114,126)	(82,041)
Net Cash Flows from Investing Activities	(573,461)	(662,980)	(464,655)
Cash Flows from Financing Activities			
Change in Short-Term Debt	114,000	287,500	(11,499)
Issuance of Common Stock	117	11,301	15,585
Retirement of Preferred Stock	(61,895)	—	(78,105)
Issuance of Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership	50,000	—	81,032
Issuance of Long-Term Debt	161,813	43,700	182,540
Retirement of Long-Term Debt	(283,303)	(427,463)	(575,713)
Loss on Reacquired Debt	22,752	24,724	12,302
Dividends on Preferred and Common Stock	(417,383)	(411,569)	(390,340)
Change in Dividends Payable	(5,438)	1,685	5,626
Expenses of Issuing Long-Term Debt and Capital Stock	(2,084)	890	(577)
Capital Lease Payments	(39,100)	(31,400)	(42,900)
Net Cash Flows from Financing Activities	(460,521)	(500,632)	(802,049)
Increase (Decrease) in Cash and Cash Equivalents	4,169	8,633	(26,368)
Cash and Cash Equivalents at beginning of period	29,235	20,602	46,970
Cash and Cash Equivalents at end of period	$ 33,404	$ 29,235	$ 20,602

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

At December 31,	1997	1996
		Thousands of Dollars
Assets		
Utility Plant		
Electric-Transmission & Distribution	**$ 3,617,666**	$ 3,494,778
Electric-Generation	**1,434,895**	10,127,602
Gas	**1,071,819**	1,005,507
Common	**302,672**	317,065
	6,427,052	14,944,952
Less Accumulated Provision for Depreciation	**2,690,824**	5,046,950
	3,736,228	9,898,002
Nuclear Fuel, net	**147,359**	199,579
Construction Work in Progress	**611,204**	661,871
Leased Property, net	**175,933**	182,088
Net Utility Plant	**4,670,724**	10,941,540
Current Assets		
Cash and Temporary Cash Investments	**33,404**	29,235
Accounts Receivable, net		
Customers	**173,350**	19,159
Other	**139,996**	74,377
Inventories, at average cost		
Fossil Fuel	**84,858**	84,633
Materials and Supplies	**90,890**	119,743
Deferred Generation Costs Recoverable in Current Rates	**424,497**	—
Deferred Energy Costs-Gas	**35,665**	30,013
Other	**20,115**	63,234
Total Current Assets	**1,002,775**	420,394
Deferred Debits and Other Assets		
Competitive Transition Charge	**5,274,624**	—
Recoverable Deferred Income Taxes	**590,267**	2,325,721
Deferred Limerick Costs	**—**	361,762
Deferred Non-Pension Postretirement Benefits Costs	**97,409**	233,492
Deferred Energy Costs-Electric	**—**	92,021
Investments	**515,835**	432,574
Loss on Reacquired Debt	**83,918**	283,853
Other	**121,016**	169,262
Total Deferred Debits and Other Assets	**6,683,069**	3,898,685
Total Assets	**$ 12,356,568**	$ 15,260,619

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets *(Continued)*

At December 31,	1997	1996
		Thousands of Dollars
Capitalization and Liabilities		
Capitalization		
Common Shareholders' Equity		
Common Stock	**$ 3,517,731**	$ 3,517,614
Other Paid-In Capital	**1,239**	1,326
Retained (Deficit) Earnings	**(792,239)**	1,127,041
	2,726,731	4,645,981
Preferred and Preference Stock		
Without Mandatory Redemption	**137,472**	199,367
With Mandatory Redemption	**92,700**	92,700
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership, which holds Solely Subordinated Debentures of the Company	**352,085**	302,182
Long-Term Debt	**3,853,141**	3,935,514
Total Capitalization	**7,162,129**	9,175,744
Current Liabilities		
Notes Payable, Bank	**401,500**	287,500
Long-Term Debt Due Within One Year	**247,087**	283,303
Capital Lease Obligations Due Within One Year	**55,808**	49,347
Accounts Payable	**306,847**	212,966
Taxes Accrued	**66,397**	71,482
Interest Accrued	**77,911**	82,006
Dividends Payable	**16,969**	22,407
Deferred Income Taxes	**185,696**	2,745
Other	**260,457**	91,608
Total Current Liabilities	**1,618,672**	1,103,364
Deferred Credits and Other Liabilities		
Capital Lease Obligations	**120,125**	132,741
Deferred Income Taxes	**2,297,042**	3,745,242
Unamortized Investment Tax Credits	**318,065**	336,132
Pension Obligation	**211,596**	224,454
Non-Pension Postretirement Benefits Obligation	**324,850**	315,058
Other	**304,089**	227,884
Total Deferred Credits and Other Liabilities	**3,575,767**	4,981,511
Commitments and Contingencies (Notes 3, 4 and 5)		
Total Capitalization and Liabilities	**$ 12,356,568**	$ 15,260,619

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 (Deficit)	Preferred Stock Shares	Preferred Stock Amount
Balance at January 1, 1995	221,609	$ 3,490,728	$ 1,271	$ 810,507	3,702	$ 370,172
Net Income				609,732		
Cash Dividends Declared						
Preferred Stock						
(at specified annual rates)				(24,253)		
Common Stock ($1.65 per share)				(366,087)		
Expenses of Capital Stock Activity				(4,035)		
Capital Stock Activity						
Long-Term Incentive Plan Issuances	563	15,585		(2,156)		
Preferred Stock Issuances			55			
Preferred Stock Redemptions					(781)	(78,105)
Balance at December 31, 1995	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)				**(16,805)**		
Common Stock ($1.80 per share)				**(400,578)**		
Expenses of Capital Stock Activity				**98**		
Interest on Stock Repurchase						
Forward Contract				**(4,889)**		
Capital Stock Activity						
Long-Term Incentive Plan Issuances	**5**	**117**				
Preferred Stock Redemptions			**(87)**		**(619)**	**(61,895)**
Balance at December 31, 1997	**222,547**	**$ 3,517,731**	**$ 1,239**	**$ (792,239)**	**2,302**	**$ 230,172**

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. Significant Accounting Policies

General
The consolidated financial statements of PECO Energy Company include the accounts of its utility subsidiary companies, all of which are wholly owned. Accounting policies are 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 non-utility 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 generally accepted accounting principles 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 in the Company's accounting for unbilled revenue, the allowance for uncollectible accounts, fuel 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 regulated 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 the Company is 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 (see note 4).

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 (see note 8).

Energy and Purchased Gas Cost Adjustment Clause
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 adjustments to rates. Such rates are adjusted quarterly.

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.

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." All other utility plant continues to be valued at original cost (see note 4).

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 share of 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.

Depreciation and Decommissioning
Depreciation is provided over the estimated service lives of plant on the straight-line method. The Company is currently reviewing the useful lives of its electric generation assets. Annual depreciation provisions for financial reporting purposes, expressed as a percentage of average depreciable utility plant in service, were approximately 3.3% in 1997, 2.9% in 1996 and 2.8% in 1995. 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 electric base 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 (see note 5).

Income Taxes
The Company uses an asset and liability approach for financial accounting and reporting of income taxes. Investment tax credits are deferred and amortized to income over the estimated useful life of the related property (see note 14).

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. AFUDC is recorded as a charge to Construction Work in Progress and as a credit to Other Income and Deductions. The rates used for capitalizing AFUDC, which averaged 8.88% in 1997, 9.38% in 1996 and 9.88% in 1995, 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 will use SFAS No. 34, "Capitalizing Interest Costs," to calculate the costs during the period of construction of debt funds used to finance its electric generation-related construction projects.

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.

Capitalized Software Costs
Software projects which exceed $5 million are capitalized. At December 31, 1997 and 1996, capitalized software costs totaled $86 and $78 million (net of $29 million accumulated amortization in each year), respectively. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, not to exceed ten years.

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 will be expensed as incurred. Gains and losses on reacquired debt associated with the Company's regulated operations will continue to be deferred and amortized to interest expense over the period approved for ratemaking purposes.

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 Segment Information
The Company provides retail electric and natural gas service to the public in southeastern Pennsylvania and, in pilot programs, natural gas service to areas in Maryland and New Jersey. The Company also engages in the wholesale marketing of electricity on a national basis. The Company participates in joint ventures which provide telecommunications services in the Philadelphia area. The Company's traditional retail service territory covers 2,107 square miles. Electric service is furnished to an area of 1,972 square miles with a population of 3.6 million, including 1.6 million in the City of Philadelphia. Approximately 94% of the retail electric service area and 64% of retail kilowatthour (kWh) sales are in the suburbs around Philadelphia, and 6% of the retail service area and 36% of such sales are in the City of Philadelphia. Natural gas service is supplied in a 1,475-square-mile area of southeastern Pennsylvania adjacent to Philadelphia with a population of 1.9 million.

For the Years Ended December 31,	1997	1996	1995
			Thousands of Dollars
Electric Operations			
Operating revenues:			
Residential	**$ 1,357,449**	$ 1,370,158	$ 1,379,046
Small commercial and industrial	**778,743**	748,561	730,220
Large commercial and industrial	**1,077,374**	1,098,307	1,135,550
Other	**147,523**	140,133	136,988
Unbilled	**19,130**	(25,950)	42,580
Service territory	**3,380,219**	3,331,209	3,424,384
Interchange sales	**58,614**	25,991	17,488
Sales to other utilities	**727,836**	497,636	333,454
Total operating revenues	**4,166,669**	3,854,836	3,775,326
Operating expenses, excluding depreciation	**2,697,877**	2,243,094	2,026,112
Depreciation	**552,667**	462,315	430,993
Operating income	**$ 916,125**	$ 1,149,427	$ 1,318,221
Utility plant additions	**$ 382,157**	$ 447,105	$ 435,400

For the Years Ended December 31,	1997	1996	1995
			Thousands of Dollars
Gas Operations			
Operating revenues:			
Residential	**$ 16,852**	$ 15,716	$ 15,482
House heating	**265,299**	249,507	235,456
Commercial and industrial	**144,801**	132,822	125,631
Other	**3,228**	11,462	5,382
Unbilled	**(969)**	(4,250)	6,540
Subtotal	**429,211**	405,257	388,491
Other revenues (including transported for customers)	**22,021**	23,557	22,339
Total operating revenues	**451,232**	428,814	410,830
Operating expenses, excluding depreciation	**333,798**	303,054	301,994
Depreciation	**27,928**	26,686	26,261
Operating income	**$ 89,506**	$ 99,074	$ 82,575
Utility plant additions	**$ 85,212**	$ 68,394	$ 63,192
Identifiable Assets* at December 31,			
Electric	**$ 9,610,984**	$ 10,287,444	$ 10,408,105
Gas	**966,685**	858,471	785,881
Nonallocable assets	**1,778,899**	4,114,704	4,114,519
Total assets	**$ 12,356,568**	$ 15,260,619	$ 15,308,505

* Includes utility plant less accumulated depreciation, inventories, segment-specific regulatory assets and allocated common utility property.

3. Rate Matters

Competition Act

The Electricity Generation Customer Choice and Competition Act (Competition Act) was enacted in December 1996, providing for the restructuring of the electric utility industry in Pennsylvania, including retail competition for generation beginning in 1999. The Competition Act requires the unbundling of electric services into separate generation, transmission and distribution services with open retail competition for generation. Electric distribution and transmission services will remain regulated by the PUC. The Competition Act requires utilities to submit to the PUC restructuring plans, including their quantification of stranded costs (the loss in value of the Company's electric generation-related assets, which will result from competition). The Competition Act authorizes the recovery of stranded costs through charges to distribution customers for up to nine years (or for an alternative period determined by the PUC for good cause shown). During that period, the utility is subject to a rate cap which provides that total charges to customers cannot exceed rates in place as of December 31, 1996, subject to certain exceptions. The Competition Act also caps transmission and distribution rates from December 31, 1996 through June 30, 2001, subject to certain exceptions.

Pursuant to the Competition Act, in April 1997, the Company filed with the PUC a comprehensive restructuring plan detailing its proposal to implement full customer choice of electric generation supplier. The Company's restructuring plan identified $7.5 billion of stranded costs. In August 1997, the Company and various intervenors in the Company's restructuring proceeding filed with the PUC a Joint Petition for Partial Settlement (Pennsylvania Plan).

In December 1997, the PUC rejected the Pennsylvania Plan and entered an Opinion and Order, revised in January 1998 (PUC Restructuring Order), that deregulates the Company's electric generation operations. The PUC Restructuring Order allows the Company to recover $4.9 billion on a discounted basis, or $5.3 billion on a book value basis, over 8 1/2 years beginning in 1999. Recovery of allowed stranded costs will be through a separate charge to be levelized over the recovery period using a 7.47% cost of capital. Other major provisions of the PUC Restructuring Order include capping customer bills at the year-end 1996 system-wide average of 9.95 cents per kWh; beginning January 1, 1999, unbundling rates into a transmission and distribution component, the charge for recovery of stranded costs and a "shopping credit" for generation; and phasing-in customer choice of electric generation supplier for all customers in three steps: one-third of the peak load of each customer class on January 1, 1999, one-third on January 2, 1999 (one day later) and the remainder on January 2, 2000. To encourage competition, the PUC established the "shopping credit" for generation in excess of current market prices.

On January 21, 1998, the Company filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania seeking injunctive and monetary relief on the grounds that the Competition Act and the PUC Restructuring Order: (1) are pre-empted by Section 201(b) of the Federal Power Act; (2) effect a taking of private property without just compensation in violation of the Fifth and Fourteenth Amendments to the U.S. Constitution; (3) violate the Due Process Clause, the Contract Clause and the First Amendment of the U.S. Constitution; and (4) deprive the Company of certain other federally protected rights.

On January 22, 1998, the Company filed two Petitions for Review in the Commonwealth Court of Pennsylvania, appealing the PUC Restructuring Order. The petitions state that the PUC Restructuring Order must be set aside because it is based upon errors of law, is not supported by substantial evidence, constitutes an arbitrary and capricious abuse of administrative discretion and deprives the Company of the due process of law, to which it is entitled under Article I of the Pennsylvania Constitution.

Limerick

Under its electric tariffs through December 31, 1997, the Company was recovering $285 million of deferred Limerick costs representing carrying charges and depreciation associated with 50% of Limerick common facilities. The Company also deferred certain operating and maintenance expenses, depreciation and accrued carrying charges on its capital investment in Limerick Unit No. 2 and 50% of Limerick common facilities. These costs were included in base rates and were being recovered over a nine-year period beginning October 1, 1996. The Company was also recovering $137 million of Limerick Unit No. 1 costs over a ten-year period without a return on investment. At December 31, 1997, the unamortized portion of these regulatory assets were included as part of electric generation-related regulatory assets (see note 4).

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 of energy savings 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 and 1995, the Company recorded as revenue net of fuel costs $82 and $79 million, respectively, 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. Effective December 31, 1997, the Company ceased this increased depreciation since this Declaratory Order has been superseded by the PUC Restructuring Order. At December 31, 1997, the $90 million of depreciation and amortization that would have been recognized in 1998 was deferred as a regulatory asset, since the Company's rates will continue to be cost-based until January 1, 1999, and will be amortized and recovered in 1998.

Recovery of Non-Pension Postretirement Benefits Costs

Effective January 1995, the Company increased electric base rates by $25 million per year to recover the increased costs, including the annual amortization of the transition obligation (over 18 years) deferred in 1994 and 1993, associated with the implementation of SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (see note 7). During 1997 and 1996, the Company deposited $26 and $47 million, respectively, in trust accounts to fund its retail electric non-pension postretirement benefits costs. These costs include amounts charged to operating expense or capitalized during 1997 and 1996. At December 31, 1997, $121 million of the previously recorded transition obligation was included as part of electric generation-related regulatory assets (see note 4).

The Company recognizes $2.8 million in non-pension postretirement benefits costs annually associated with gas utility operations. During 1997 and 1996, the Company deposited $2.8 and $2.9 million, respectively, in trust accounts to fund its gas non-pension postretirement benefits costs.

Energy Cost Adjustment

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 years ended December 31, 1996 and 1995, the Company recorded bonuses of $22 and $13 million, respectively.

4. Accounting Changes

The Company accounts for all of its regulated operations in accordance with SFAS No. 71 which allows 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.

In 1997, the Financial Accounting Standards Board (FASB) through its Emerging Issues Task Force (EITF) issued EITF No. 97-4, "Deregulation of the Pricing of Electricity - Issues Related to the Application of FASB Statements No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71." The EITF agreed that: a) an entity should cease to apply SFAS No. 71 no later than the date the specific deregulation plan is enacted and the details of that plan are known, and b) both stranded costs and regulated assets and liabilities should continue to be recognized to the extent that the transition plan provides for their recovery through the regulated transmission and distribution portion of the business.

The Company believes that the PUC Restructuring Order provides sufficient details regarding the deregulation of the Company's electric generation operations to require the Company to discontinue the application of SFAS No. 71 for those operations. Effective December 31, 1997, the Company adopted the provisions of SFAS No. 101 for its electric generation operations. SFAS No. 101 requires a determination of impairment of plant assets under SFAS No. 121, and the elimination of all effects of rate regulation that have been recognized as assets and liabilities pursuant to SFAS No. 71.

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 generation 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 will continue to be cost-based until January 1, 1999, \$0.3 billion representing depreciation expense on electric generation-related assets in 1998 has been reclassified to a regulatory asset and will be amortized and recovered in 1998.

At December 31, 1997, the Company had \$2.7 billion of electric generation-related regulatory assets, of which \$0.1 billion will be amortized and recovered through cost-based rates 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 PUC Restructuring Order allows the Company to recover \$4.9 billion on a discounted basis, or \$5.3 billion on a book-value basis, of its generation-related stranded costs from customers. This results in a net unrecoverable amount of \$3.1 billion.

Although the Company is appealing the PUC Restructuring Order, Management believes that EITF No. 97-4 required it to write off all electric generation-related stranded costs for which recovery through rates has not been provided. 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.

A summary as of December 31, 1997 of the electric generation-related stranded costs and the amount of such stranded costs written-off by the Company is shown in the following table:

	(Thousands of Dollars)
Electric generation-related asset impairment determined pursuant to SFAS No. 121	
Net book value of electric generation-related assets before write-down	\$ 7,115,155
December 31, 1998 market value of electric generation-related assets pursuant to SFAS No. 121	(990,376)
Expected 1998 change in net plant recognized for recovery until cost-based rates cease at December 31, 1998	(303,800)
Electric generation-related asset impairment	**5,820,979**
Electric generation-related regulatory assets	
Recoverable Deferred Income Taxes	1,762,946
Deferred Limerick Costs	321,420
Deferred Non-Pension Postretirement Benefits Other Than Pensions	120,899
Deferred Energy Costs - Electric	92,021
Loss on Reacquired Debt	177,183
Additional assets written-off pursuant to discontinuance of SFAS No. 71	104,818
Other	90,480
Regulatory asset recognized for recovery until cost-based rates cease at December 31, 1998	(91,497)
Total electric generation-related regulatory assets	**2,578,270**
Total electric generation-related stranded costs	**8,399,249**
Amounts approved for collection from customers (regulatory asset pursuant to EITF No. 97-4)	**(5,274,624)**
Total Extraordinary Item	**\$ 3,124,625**

Due to the market-based pricing of electric generation provisions of the PJM Interconnection, L.L.C. restructuring order approved by the FERC in November 1997, the Company believes that its wholesale energy sales operations are no longer subject to the provisions of SFAS No. 71. Based on projections of the Company's retail load growth, the Company believes all of its owned generation capacity is necessary to meet its electric retail load. As a result, the discontinuance of SFAS No. 71 for its wholesale energy sales operations has not resulted in an additional charge against income.

The Company believes that its electric transmission and distribution system and gas operations continue to meet the provisions of SFAS No. 71. The Company believes that it is probable that regulatory assets associated with these operations will be recovered.

The Company has adopted SFAS No. 128, "Earnings Per Share," which is designed to simplify the existing computational guidelines for the earnings per share (EPS) information provided in financial statements, to revise the disclosure requirements and to increase the comparability of EPS data on an international basis. Pursuant to SFAS No. 128, the Company reflected on its Consolidated Statements of Income basic EPS and dilutive EPS for the years ended December 31, 1997, 1996 and 1995. Adoption of SFAS No. 128 did not impact the amount of EPS reported and there is no difference in the amounts calculated as basic EPS and dilutive EPS.

5. Commitments and Contingencies

Capital Commitments

Total capital expenditures, primarily for utility plant, are estimated to be $600 million in 1998. Due to the expected adverse impact of the PUC Restructuring Order and competition for electric generating services on its future capital resources, the Company is currently evaluating its capital commitments for 1999 and beyond. Certain facilities under construction and to be constructed may require permits and licenses which the Company has no assurance will be granted. The Company has undertaken a number of new ventures, principally through its Telecommunications Group, some of which require significant cash commitments. For 1998, the Company's expected capital expenditures include approximately $150 million in such ventures.

The Company's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws.

Nuclear Insurance

The Price-Anderson Act currently limits the liability of nuclear reactor owners to $8.9 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 $8.7 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 $79 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, 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 reactor stabilization and site decontamination. If the decision is made 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 $26 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 $13 million per year.

Nuclear Decommissioning and Spent Fuel Storage

The Company's current estimate of its nuclear facilities' decommissioning cost of $1.5 billion in 1997 dollars is being collected through electric rates over the life of each generating unit. Beginning in 1999, these amounts will be recoverable through transmission and distribution rates. Under current rates, the Company collects and expenses approximately $20 million annually from customers. The expense is accounted for as a component of depreciation expense and accumulated depreciation. At December 31, 1997 and 1996, $294 and $256 million, respectively, was included in accumulated depreciation. In order to fund future decommissioning costs, at December 31, 1997 and 1996, the Company held $320 and $266 million, respectively, in trust accounts which are included as an Investment in the Company's Consolidated Balance Sheet and include both net unrealized and realized gains. Net unrealized gains of $43 and $26 million were recognized as a Deferred Credit in the Company's Consolidated Balance Sheet at December 31, 1997 and 1996, respectively. The Company recognized net realized gains of $11, $10 and $9 million as Other Income in the Company's Consolidated Statement of Income for the years ended December 31, 1997, 1996 and 1995, respectively. 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.

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 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 have filed a Petition for Reconsideration of the decision. The U.S. House of Representatives and the U.S. Senate passed separate bills in 1997 authorizing construction of a temporary storage facility which could accept spent nuclear fuel from utilities in 2003. 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 will begin 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. Public Service Electric and Gas Company (PSE&G) is the operator of Salem, which is 42.59% owned by the Company.

Energy Commitments

The Company's electric utility operations include the wholesale marketing of electricity. At December 31,1997, the Company had long-term commitments relating to the purchase from unaffiliated utilities and others energy associated with 1,330 MW of capacity in 1998, with 2,540 MW of capacity during the period 1999 through 2002 and with 2,430 MW of capacity thereafter. During 1997, purchases under long-term commitments resulted in expenditures of $311 million. As of December 31, 1997, these purchases result in commitments of approximately $240 million for 1998, $620 million for 1999 through 2002 and $830 million thereafter. These purchases will be utilized through a combination of sales to jurisdictional customers, long-term sales to other utilities and open market sales. Under some of these contracts, the Company may purchase, at its option, additional power as needed.

In the wholesale market, the Company has increased its sales to other utilities, but increased competition has reduced the Company's profit margins on these sales. At December 31, 1997, the Company had entered into long-term agreements with unaffiliated utilities to sell energy associated with 4,280 MW of capacity, of which 540 MW of these agreements are for 1998, 1,700 MW are for 1999 through 2002 and the remaining 2,040 MW extend through 2022.

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 27 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 two sites. Six other sites are currently under some degree of active study and/or remediation.

As of December 31, 1997 and 1996, the Company had accrued $63 and $28 million, respectively, for environmental investigation and remediation costs, including $35 and $16 million, respectively, for MGP investigation and remediation, that currently can be reasonably estimated. The Company cannot predict 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.

Shutdown of Salem Generating Station

PSE&G removed Salem Units No. 1 and No. 2 from service in the second quarter of 1995 and informed the NRC at that time that it had determined to keep the Salem units shut down pending review and resolution of certain equipment and management issues and NRC agreement that each unit is sufficiently prepared to restart. Unit No. 2 returned to service on August 30, 1997, and PSE&G estimates the restart of Unit No. 1 to occur late in the first quarter of 1998. For the years ended December 31, 1997, 1996 and 1995, the Company incurred and expensed approximately $152, $149 and $50 million of shutdown-related replacement power and maintenance costs, respectively (see note 21).

Telecommunications

The Company periodically reviews its investments to determine that they are properly valued in its financial statements. Due to circumstances involved in the Federal Communication Commission's auctioning of the personal communications systems "C-block" licenses, the Company has determined that $20 million of its telecommunications investments were impaired at December 31, 1997. Accordingly, at December 31, 1997, the Company incurred a $20 million charge against Other Income and Deductions to write off this telecommunications investment.

Litigation

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 non-contributory trusteed retirement plan applicable to all regular employees. The benefits are based primarily upon employees' years of service and average earnings prior to retirement. The Company's funding policy is to contribute, at a minimum, amounts sufficient to meet the Employee Retirement Income Security Act requirements. Approximately 89%, 80% and 74% of pension costs were charged to operations in 1997, 1996 and 1995, respectively, and the remainder, associated with construction labor, to the cost of new utility plant.

Pension costs for 1997, 1996 and 1995 included the following components:

	1997	1996	1995
			Thousands of Dollars
Service cost benefits earned during the period	**$ 25,368**	$ 27,627	$ 19,710
Interest cost on projected benefit obligation	**150,057**	145,570	147,261
Actual return on plan assets	**(377,803)**	(320,247)	(456,057)
Amortization of transition asset	**(4,538)**	(4,538)	(4,538)
Amortization and deferral	**197,480**	154,402	300,214
Net pension cost	**$ (9,436)**	$ 2,814	$ 6,590

The changes in net periodic pension costs in 1997, 1996 and 1995 were as follows:

	1997	1996	1995
			Thousands of Dollars
Change in number, characteristics and salary levels of participants and net actuarial gain	**$ (7,839)**	$ (12,893)	$ 1,486
Change in plan provisions	**3,118**	—	(8,305)
Change in actuarial assumptions	**(7,529)**	9,117	(3,136)
Net change	**$ (12,250)**	$ (3,776)	$ (9,955)

Plan assets consist principally of common stock, U.S. government obligations and other fixed income instruments. In determining pension costs, the assumed long-term rate of return on assets was 9.5% for 1997, 1996 and 1995.

The weighted-average discount rate used in determining the actuarial present value of the projected benefit obligation was 7.25% at December 31, 1997, 7.75% at December 31, 1996 and 7.25% at December 31, 1995. The average rate of increase in future compensation levels ranged from 4% to 6% at December 31, 1997, 1996 and 1995.

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

The funded status of the plan at December 31, 1997 and 1996 is summarized as follows:

	1997	1996
		Thousands of Dollars
Actuarial present value of accumulated plan benefit obligations:		
Vested benefit obligation	**$ 1,794,222**	$ 1,657,098
Accumulated benefit obligation	**1,890,848**	1,742,116
Projected benefit obligation for services rendered to date	**$ 2,141,040**	$ 1,982,915
Plan assets at fair value	**(2,538,039)**	(2,302,935)
Funded status	**(396,999)**	(320,020)
Unrecognized transition asset	**35,713**	40,251
Unrecognized prior service costs	**(83,188)**	(92,682)
Unrecognized net gain	**649,903**	588,013
Pension obligation recognized on the balance sheet	**$ 205,429**	$ 215,562

7. Non-Pension Postretirement Benefits

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 transition obligation, which represents the previously unrecognized accumulated non-pension postretirement benefit obligation, is being amortized on a straight-line basis over an allowed 20-year period. At December 31, 1997, the Company accelerated recognition of $121 million of its non-pension postretirement benefits obligation related to its electric generation operations and included this regulatory asset as part of electric generation-related regulatory assets (see note 4).

The transition obligation was determined by application of the terms of medical, dental and life insurance plans, including the effects of established maximums on covered costs, together with relevant actuarial assumptions and health care cost trend rates, which are projected to range from 7% in 1998 to 5% in 2002. The effect of a 1% annual increase in these assumed cost trend rates would increase the accumulated postretirement benefit obligation by $85 million and the annual service and interest costs by $10 million.

Total costs for all plans were $73 million in 1997 and $71 million in 1996 and 1995.

The net periodic benefits costs for 1997, 1996 and 1995 included the following components:

	1997	1996	1995
			Thousands of Dollars
Service cost benefits earned during the period	**$ 14,401**	$ 11,855	$ 8,681
Interest cost on projected benefit obligation	**54,149**	48,524	48,641
Amortization of transition asset	**14,882**	14,882	14,882
Actual return on plan assets	**(22,691)**	(13,257)	(2,075)
Deferred asset gain	**12,707**	9,320	1,359
Net postretirement benefits costs	**$ 73,448**	$ 71,324	$ 71,488

Plan assets consist principally of common stock, U.S. government obligations and other fixed income instruments. In determining non-pension postretirement benefits costs, the assumed long-term rate of return on assets was 8% for 1997, 1996 and 1995.

The weighted-average discount rate used in determining the actuarial present value of the projected benefit obligation was 7.75% at January 1, 1997, 7.50% at January 1, 1996 and 8.50% at January 1, 1995. The average rate of increase in future compensation levels ranged from 4% to 6% at December 31, 1997, 1996 and 1995.

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

The funded status of the plan at December 31, 1997 and 1996 is summarized as follows:

	1997	1996
	Thousands of Dollars	
Accumulated postretirement benefit obligation:		
Retirees	**$ 697,084**	$ 609,206
Fully eligible active plan participants	**8,875**	4,509
Other active plan participants	**73,272**	48,986
Total	**779,231**	662,701
Plan assets at fair value	**(178,045)**	(126,661)
Accumulated postretirement benefit obligation in excess of plan assets	**601,186**	536,040
Unrecognized transition obligation	**(223,226)**	(238,108)
Unrecognized net gain	**(53,110)**	17,126
Accrued postretirement benefits obligation recognized on the balance sheet	**$ 324,850**	$ 315,058

Measurement of the accumulated postretirement benefits obligation was based on a 7.25% and 7.75% assumed discount rate as of December 31, 1997 and 1996, respectively.

8. Accounts Receivable

Accounts receivable at December 31, 1997 and 1996 included unbilled operating revenues of $135 and $117 million, respectively. Accounts receivable at December 31, 1997 and 1996 were net of an allowance for uncollectible accounts of $32 and $24 million, respectively.

The Company has adopted SFAS No. 125, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," which provides a standard for distinguishing between transfers of financial assets that are accounted for as sales from those that are accounted for as secured borrowings.

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, 1997, the Company had sold a $425 million interest in accounts receivable, consisting of a $296 million interest in accounts receivable which the Company accounts for as a sale under SFAS No. 125 and a $129 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.

9. Common Stock

At December 31, 1997 and 1996, common stock without par value consisted of 500,000,000 shares authorized and 222,546,562 and 222,542,087 shares outstanding, respectively. At December 31, 1997, 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, 1997, based on the closing price of the Company's Common Stock on that date, the Company would have received approximately 1,160,000 shares of Company common stock.

Long-Term Incentive Plan (LTIP)

The Company maintains an 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, dividend equivalents and shares of restricted common stock. 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:

		1997	1996
		Thousands of Dollars	
Earnings applicable to common stock	As reported	**$ (1,513,910)**	$ 499,169
	Pro forma	**$ (1,515,895)**	$ 497,887
Earnings per average common share (Dollars)	As reported	**$ (6.80)**	$ 2.24
	Pro forma	**$ (6.81)**	$ 2.24

Options granted under the LTIP become exercisable one year after the date of grant and all options expire 10 years from the date of the grant. Information with respect to the LTIP at December 31, 1997 and changes for the three years then ended, is as follows:

	Shares 1997	**Weighted Average Exercise Price (per share) 1997**	Shares 1996	Weighted Average Exercise Price (per share) 1996	Shares 1995	Weighted Average Exercise Price (per share) 1995
Balance at January 1	**2,961,194**	**$ 26.68**	2,591,765	$ 26.16	2,651,397	$ 26.73
Options granted	**1,139,000**	**22.49**	786,500	28.12	850,700	26.46
Options exercised	**—**	**—**	(369,871)	25.07	(561,232)	23.91
Options cancelled	**(283,400)**	**24.96**	(47,200)	29.36	(349,100)	35.57
Balance at December 31	**3,816,794**	**26.14**	2,961,194	26.68	2,591,765	26.16
Exercisable at December 31	**2,800,794**	**26.65**	2,192,694	26.17	1,813,565	25.91
Weighted average fair value of options granted during year		**$ 2.97**		$ 2.78		$ 2.91

The fair value of each option is estimated on the date of the grant using the Black-Scholes option-pricing model, with the following weighted average assumptions used for grants in 1997, 1996 and 1995, respectively:

	1997	1996	1995
Dividend yield	6.2%	6.2%	6.2%
Expected volatility	19.5%	16.6%	15.3%
Risk-free interest rate	6.4%	5.5%	6.9%
Expected life (years)	5	5	5

At December 31, 1997, the option groups outstanding based on ranges of exercise prices is 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	156,094	4.47	$ 18.65	117,594	$ 18.43
$20.01 - $25.00	863,500	8.23	22.35	153,000	22.66
$25.01 - $30.00	2,607,000	6.72	27.32	2,518,000	27.22
$30.01 - $50.00	190,200	9.58	33.27	12,200	37.18
Total	3,816,794			2,800,794	

10. Preferred and Preference Stock

At December 31, 1997 and 1996, Series Preference Stock consisted of 100,000,000 shares authorized, of which no shares were outstanding. At December 31, 1997 and 1996, cumulative Preferred Stock, no par value, consisted of 15,000,000 shares authorized.

	Current Redemption Price(a)	Shares Outstanding 1997	Shares Outstanding 1996	Amount Thousands of Dollars 1997	Amount Thousands of Dollars 1996
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	102.00	**150,000**	150,000	**15,000**	15,000
$3.80	106.00	**300,000**	300,000	**30,000**	30,000
$7.96	—	**—**	618,954	**—**	61,895
$7.48	(b)	**500,000**	500,000	**50,000**	50,000
		1,374,720	1,993,674	**137,472**	199,367
Series (with mandatory redemption)					
$6.12	(c)	**927,000**	927,000	**92,700**	92,700
Total preferred stock		**2,301,720**	2,920,674	**$ 230,172**	$ 292,067

(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) There are no annual sinking fund requirements in 1998. 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, 1997 and 1996, 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 three and two series, respectively, of cumulative COMRPS, each with a liquidation value of $25 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 securities. The interest paid by the Company on the debentures is included in Other Income and Deductions in the Consolidated Statements of Income and is deductible for income tax purposes.

At December 31,	Mandatory Redemption Date	Distribution Rate	Trust Receipts Outstanding 1997	Trust Receipts Outstanding 1996	Amount Thousands of Dollars 1997	Amount Thousands of Dollars 1996
Series						
A	2043	9.00%	**8,850,000**	8,850,000	**$ 221,250**	$ 221,250
B (a)	2025	8.72%	**3,124,183**	3,124,183	**80,835**	80,932
C (b)	2037	8.00%	**2,000,000**	—	**50,000**	—
Total			**13,974,183**	11,974,183	**$ 352,085**	$ 302,182

(a) Ownership of this series is evidenced by Trust Receipts, each representing an 8.72% COMRPS, Series B, representing limited partnership interests. The Trust Receipts were issued by PECO Energy Capital Trust I, the sole assets of which are 8.72% COMRPS, Series B. Each holder of Trust Receipts is entitled to withdraw the corresponding number of 8.72% COMRPS, Series B from the Trust in exchange for the Trust Receipts so held.

(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.

12. Long-Term Debt

At December 31,	Series	Due	1997	1996
			Thousands of Dollars	
First and refunding mortgage bonds (a)	6 1/8 %	1997	**$ —**	$ 75,000
	5 3/8 %	1998	**225,000**	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 3/8%-10 1/4 %	2003-2007	**565,625**	569,688
	(b)	2008-2012	**154,200**	154,200
	6 5/8%-8 3/4%	2018-2022	**832,130**	832,130
	7 1/8%-7 3/4%	2023-2024	**775,000**	775,000
Total first and refunding mortgage bonds			**3,706,955**	3,786,018
Notes payable			**15,574**	—
Term loan agreements	(c)	1997	**—**	175,000
Pollution control notes	(d)	2016-2034	**212,705**	212,705
Medium-term notes	(e)	1998-2005	**62,400**	74,400
Note payable - accounts receivable agreement	(f)	2000	**128,999**	—
Unamortized debt discount and premium, net			**(26,405)**	(29,306)
Total long-term debt			**4,100,228**	4,218,817
Due within one year	(g)		**247,087**	283,303
Long-term debt included in capitalization	(h)		**$ 3,853,141**	$ 3,935,514

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

(b) Floating rates, which were an average annual interest rate of 3.725% at December 31, 1997.

(c) The Company has a $900 million unsecured revolving credit facility with a group of banks. The credit facility is composed 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 the Company's commercial paper program, which was expanded from $300 million to $600 million in 1997. There was no debt outstanding under this credit facility at December 31, 1997.

(d) Floating rates, which were an average annual interest rate of 3.75% at December 31, 1997.

(e) Medium-term notes collateralized by mortgage bonds. The average annual interest rate was 8.75% at December 31, 1997.

(f) See note 8.

(g) Long-term debt maturities, including mandatory sinking fund requirements, in the period 1998-2002 are as follows: 1998 - $247,087,409; 1999 - $361,945,982; 2000 - $137,129,159; 2001 - $338,433,453; 2002 - $508,759,067.

(h) The annualized interest on long-term debt at December 31, 1997, was $286 million, of which $269 million was associated with mortgage bonds and $17 million was associated with other long-term debt.

13. Short-Term Debt

	1997	1996	1995
			Thousands of Dollars
Average borrowings	**$ 248,111**	$ 198,090	$ 17,560
Average interest rates, computed on daily basis	**5.83%**	5.64%	6.25%
Maximum borrowings outstanding	**$ 464,500**	$ 369,500	$ 182,000
Average interest rates, at December 31	**6.74%**	6.90%	—

The Company has a $600 million commercial paper program which is supported by the $900 million revolving credit facility (see note 12). At December 31, 1997, $314 million of commercial paper was outstanding. At December 31, 1997, the Company had formal and informal lines of credit with banks aggregating $75 million. At December 31, 1997, no short-term debt was outstanding under these lines.

14. Income Taxes

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

For the Years Ended December 31,	1997	1996	1995
			Thousands of Dollars
Included in operations:			
Federal			
Current	**$ 251,509**	$ 126,471	$ 190,796
Deferred	**(11,378)**	154,564	167,526
Investment tax credit, net	**(18,201)**	(15,979)	(21,679)
State			
Current	**76,689**	62,839	79,086
Deferred	**(5,850)**	12,206	15,988
	292,769	340,101	431,717
Included in extraordinary item:			
Federal			
Current	**(123)**	—	—
Deferred	**(987,234)**	—	—
State			
Current	**(29)**	—	—
Deferred	**(303,575)**	—	—
	(1,290,961)	—	—
Total	**$ (998,192)**	$ 340,101	$ 431,717

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

	1997	1996	1995
			Thousands of Dollars
Net Income	**$ 336,558**	$ 517,205	$ 609,732
Total income tax provisions	**292,769**	340,101	431,717
Income before income taxes	**$ 629,327**	$ 857,306	$ 1,041,449
Income taxes on above at federal statutory rate at 35%	**$ 220,264**	$ 300,057	$ 364,507
Increase (decrease) due to:			
Property basis differences	**40,828**	9,903	11,196
State income taxes, net of federal income tax benefit	**46,046**	48,779	61,799
Amortization of investment tax credit	**(18,201)**	(15,979)	(13,604)
Prior period income taxes	**(2,985)**	(1,707)	1,791
Other, net	**6,817**	(952)	6,028
Total income tax provisions	**$ 292,769**	$ 340,101	$ 431,717
Effective income tax rate	**46.5%**	39.7%	41.5%

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

	1997	1996	1995
			Thousands of Dollars
Depreciation and amortization	**$ 57,530**	$ 42,385	$ 32,287
Deferred energy costs	**2,256**	27,374	30,073
Retirement and separation programs	**(12,734)**	19,746	15,733
Incremental nuclear outage costs	**(981)**	2,440	8,079
Uncollectible accounts	**(1,710)**	(2,805)	(1,991)
Reacquired debt	**(8,607)**	(9,578)	(3,266)
Unbilled revenue	**(5,110)**	3,910	(5)
Environmental clean-up costs	**(15,121)**	(714)	2,433
Obsolete inventory	**(7,074)**	5,829	6,362
Limerick plant disallowances and phase-in plan	**(747)**	(747)	2,507
AMT credits	**—**	83,010	91,399
Other nuclear operating costs	**(9,892)**	—	—
Other	**(15,038)**	(4,080)	(97)
Subtotal	**$ (17,228)**	$ 166,770	$ 183,514
Extraordinary item	**(1,290,809)**	—	—
Total	**$ (1,308,037)**	$ 166,770	$ 183,514

The tax effect of temporary differences giving rise to the Company's net deferred tax liability as of December 31, 1997 and 1996 is as follows:

	Liability or (Asset)	
	1997	1996
		Thousands of Dollars
Nature of temporary difference:		
Plant basis difference	**$ 2,620,254**	$ 3,795,786
Deferred investment tax credit	**318,065**	336,132
Deferred debt refinancing costs	**111,651**	120,031
Other, net	**(249,167)**	(167,830)
Deferred income taxes (net) on the balance sheet	**$ 2,800,803**	$ 4,084,119

The net deferred tax liability shown above as of December 31, 1997 and 1996 is comprised of $3,153 and $4,347 million of deferred tax liabilities, and $352 and $263 million of deferred tax assets, respectively.

In accordance with SFAS No. 71, the Company recorded a recoverable deferred income tax asset of $586 and $2,322 million at December 31, 1997 and 1996, respectively. The December 31, 1997 balance was applicable only to non-electric generation 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. At December 31, 1997, $1,763 million of electric generation-related recoverable deferred income taxes were included as part of electric generation-related regulatory assets (see note 4).

The Internal Revenue Service (IRS) has completed and settled its examinations of the Company's federal income tax returns through 1986. The 1987 through 1990 federal income tax returns have been examined and the Company and the IRS have reached a tentative settlement which would not result in an adverse impact on the Company. The years 1991 through 1993 are currently being examined by the IRS.

The AMT credit was fully utilized for tax purposes at December 31, 1997, and reduced federal income taxes currently payable by $6 million in 1997.

15. Taxes, Other Than Income - Operating

For the Years Ended December 31,	1997	1996	1995
			Thousands of Dollars
Gross receipts	**$ 163,552**	$ 160,246	$ 165,172
Capital stock	**48,085**	41,972	42,444
Real estate	**69,597**	69,185	71,600
Payroll	**25,976**	27,585	30,109
Other	**2,881**	558	4,746
Total	**$ 310,091**	$ 299,546	$ 314,071

16. Leases

Leased property included in utility plant was as follows:

At December 31,	1997	1996
		Thousands of Dollars
Nuclear fuel	**$ 521,921**	$ 527,116
Electric plant	**2,321**	2,069
Gross leased property	**524,242**	529,185
Accumulated amortization	**(348,309)**	(347,097)
Net leased property	**$ 175,933**	$ 182,088

Nuclear fuel is amortized as the fuel is consumed. Amortization of leased property totaled $39, $31 and $43 million for the years ended December 31, 1997, 1996 and 1995, respectively. Other operating expenses included interest on capital lease obligations of $9 million in 1997 and 1996, and $10 million in 1995.

Minimum future lease payments as of December 31, 1997 were:

For the Years Ending December 31,	Capital Leases	Operating Leases	Total
			Thousands of Dollars
1998	$ 69,820	$ 50,584	$ 120,404
1999	68,530	49,370	117,900
2000	43,827	45,923	89,750
2001	10,892	43,219	54,111
2002	92	42,327	42,419
Remaining years	806	537,645	538,451
Total minimum future lease payments	$ 193,967	$ 769,068	$ 963,035
Imputed interest (rates ranging from 6.5% to 17.0%)	(18,034)		
Present value of net minimum future lease payments	$ 175,933		

Rental expense under operating leases totaled $74 million in 1997 and 1996, and $115 million in 1995.

17. Jointly Owned Electric Utility Plant

The Company's ownership interests in jointly owned electric utility plant at December 31, 1997 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	$ 307,029	$ 18,331	$ 110,661	$ 184,037	$ 81,072
Accumulated depreciation	175,304	11,134	66,487	78,605	31,273
Construction work in progress	50,208	713	10,067	9,100	1,943

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:

	1997	1996	1995
			Thousands of Dollars
Cash paid during the year:			
Interest (net of amount capitalized)	**$ 405,838**	$ 415,063	$ 449,664
Income taxes (net of refunds)	**345,232**	251,554	257,677
Noncash investing and financing:			
Capital lease obligations incurred	**32,909**	33,063	48,760

19. Investments

At December 31,	**1997**	1996
		Thousands of Dollars
Trust accounts for decommissioning nuclear plants	**$ 320,442**	$ 266,270
Telecommunications ventures	**85,601**	79,833
Energy services and other ventures	**65,578**	44,023
Nonutility property	**24,697**	26,349
Other	**19,517**	16,099
Total	**$ 515,835**	$ 432,574

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, 1997 and 1996 were as follows:

Thousands of Dollars	**1997**		1996	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and temporary cash investments	**$ 33,404**	**$ 33,404**	$ 29,235	$ 29,235
Long-term debt (including amounts due within one year)	**4,100,228**	**4,210,885**	4,218,817	4,239,357
Trust accounts for decommissioning nuclear plants	**320,442**	**320,442**	266,270	266,270

Financial instruments which potentially subject the Company to 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.

21. Other Income

Settlement of Salem Litigation

On December 31, 1997, the Company received $70 million pursuant to the May 1997 settlement agreement with PSE&G resolving a suit filed by the Company concerning the shutdown of Salem. The agreement also provides that if the outage exceeds 64 reactor unit months, PSE&G will pay the Company $1 million per reactor unit month. As of December 31, 1997, the shutdown of Salem totaled 58 reactor unit months. During the second quarter of 1997, the Company recorded $70 million ($41 million net of income taxes) as Other Income.

Sale of Subsidiary

In June 1995, the Company completed the sale of Conowingo Power Company to Delmarva Power & Light Company (Delmarva) for $150 million. The transaction also included a ten-year contract for the Company to sell power to Delmarva. The Company's gain of $59 million ($27 million net of taxes) on the sale was recorded in the second quarter of 1995.

22. Regulatory Assets and Liabilities

At December 31, 1997 and 1996, the Company had deferred the following regulatory assets on the Consolidated Balance Sheet:

	1997	1996
	Thousands of Dollars	
Competitive transition charge (see note 4)	**$ 5,274,624**	$ —
Recoverable deferred income taxes (see note 14)	**585,661**	2,321,692
Deferred generation costs recoverable in current rates (see note 4)	**424,497**	—
Deferred Limerick costs (see note 3)	**—**	361,762
Loss on reacquired debt	**83,918**	283,853
Compensated absences	**3,881**	37,727
Deferred energy costs (see note 3)	**35,665**	122,034
Non-pension postretirement benefits (see note 3)	**97,409**	233,492
Total	**$ 6,505,655**	$ 3,360,560

23. 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	**1997**	1996	**1997**	1996	**1997**	1996
Quarter ended						
March 31	**$ 1,163**	$ 1,171	**$ 302**	$ 357	**$ 113**	$ 150
June 30	**1,032**	989	**250**	267	**123**	99
September 30	**1,278**	1,110	**388**	347	**158**	150
December 31	**1,144**	1,014	**66**	278	**(1,891)**	118

	Earnings Applicable to Common Stock		Average Shares Outstanding		Earnings Per Average Share	
Millions of Dollars	**1997**	1996	**1997**	1996	**1997**	1996
Quarter ended						
March 31	**$ 109**	$ 146	**222.5**	222.4	**$ 0.49**	0.65
June 30	**118**	94	**222.5**	222.5	**0.53**	0.43
September 30	**154**	145	**222.5**	222.5	**0.69**	0.65
December 31	**(1,895)**	114	**222.5**	222.5	**(8.51)**	0.51

The decrease in 1997 first quarter results was primarily due to increased fuel and energy interchange expense resulting primarily from additional purchases needed for increased sales to other utilities and higher replacement power costs due to the Salem outage, milder weather and increased depreciation of assets associated with Limerick.

The increase in 1997 second quarter results was primarily due to the recognition of the settlement of litigation arising from the Salem outage. Offsetting this increase was higher depreciation of assets associated with Limerick.

The decrease in 1997 fourth quarter results was primarily due to the extraordinary charge of $8.24 per share resulting from the effects of the PUC Restructuring Order and 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.

Financial Statistics

Summary of Earnings and Financial Condition

For the Years Ended December 31,	**1997**	1996	1995	1994	1993	1992
						Millions of Dollars
Income Data						
Operating Revenues	**$ 4,618**	$ 4,284	$ 4,186	$ 4,041	$ 3,988	$ 3,963
Operating Income	**1,006**	1,249	1,401	1,064	1,390	1,298
Income before Extraordinary Item	**337**	517	610	427	591	479
Extraordinary Item (net of income taxes)	**(1,834)**	—	—	—	—	—
Net Income	**(1,497)**	517	610	427	591	479
Earnings Applicable to Common Stock Before Extraordinary Item	**(1,514)**	499	587	389	542	418
Earnings per Average Common Share Before Extraordinary Item *(Dollars)*	**1.44**	2.24	2.64	1.76	2.45	1.90
Extraordinary Item *(Per Share)*	**(8.24)**	—	—	—	—	—
Earnings per Average Common Share	**(6.80)**	2.24	2.64	1.76	2.45	1.90
Dividends per Common Share *(Dollars)*	**1.80**	1.755	1.65	1.545	1.43	1.325
Common Stock Equity *(Per Share)*	**12.25**	20.88	20.40	19.41	19.25	18.24
Average Shares of Common Stock Outstanding *(Millions)*	**222.5**	222.5	221.9	221.6	221.1	220.2

At December 31,						
Balance Sheet Data						
Net Utility Plant	**$ 4,495**	$ 10,760	$ 10,758	$ 10,829	$ 10,763	$ 10,691
Leased Property, net	**176**	182	181	174	194	210
Total Current Assets	**1,003**	420	426	427	515	550
Total Deferred Debits and Other Assets	**6,683**	3,899	3,944	3,992	3,905	1,127
Total Assets	**$ 12,357**	$ 15,261	$ 15,309	$ 15,422	$ 15,377	$ 12,578
Common Shareholders' Equity	**$ 2,727**	$ 4,646	$ 4,531	$ 4,303	$ 4,263	$ 4,022
Preferred and Preference Stock Without Mandatory Redemption	**137**	199	199	277	423	423
With Mandatory Redemption	**93**	93	93	93	187	231
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership	**352**	302	302	221	—	—
Long-term Debt	**3,853**	3,936	4,199	4,786	4,884	5,204
Total Capitalization	**7,162**	9,176	9,324	9,680	9,757	9,880
Total Current Liabilities	**1,619**	1,103	1,052	850	954	830
Total Deferred Credits and Other Liabilities	**3,576**	4,982	4,933	4,892	4,666	1,868
Total Capitalization and Liabilities	**$ 12,357**	$ 15,261	$ 15,309	$ 15,422	$ 15,377	$ 12,578

Operating Statistics

For the Years Ended December 31,	**1997**	1996	1995	1994	1993	1992
Electric Operations						
Output *(Millions of Kilowatthours)*						
Fossil	**9,659**	10,856	10,792	11,239	10,352	8,082
Nuclear	**25,853**	24,373	25,499	28,195	27,026	24,428
Hydro	**1,558**	2,404	1,425	1,970	1,699	1,803
Pumped storage output	**1,403**	1,540	1,741	1,596	1,478	1,597
Pumped storage input	**(1,924)**	(2,230)	(2,507)	(2,256)	(2,192)	(2,217)
Purchase and interchange	**29,615**	19,539	13,945	6,164	6,447	8,675
Internal combustion	**144**	179	175	106	56	29
Total electric output	**66,308**	56,661	51,070	47,014	44,866	42,397
Sales *(Millions of Kilowatthours)*						
Residential	**10,407**	10,671	10,636	10,859	10,609	9,965
Small commercial and industrial	**6,685**	6,491	6,200	6,150	5,769	5,396
Large commercial and industrial	**15,034**	15,208	15,763	15,968	15,956	15,829
Other	**841**	902	860	791	771	962
Unbilled	**70**	(327)	535	(205)	31	(159)
Service territory	**33,037**	32,945	33,994	33,563	33,136	31,993
Interchange sales	**1,927**	935	496	768	457	1,231
Sales to other utilities	**28,893**	20,243	14,041	10,039	8,670	6,699
Total electric sales	**63,857**	54,123	48,531	44,370	42,263	39,923
Number of Customers, *December 31,*						
Residential	**1,333,861**	1,324,448	1,321,379	1,350,210	1,341,873	1,333,926
Small commercial and industrial	**144,142**	142,431	141,653	143,605	142,363	141,253
Large commercial and industrial	**3,308**	3,299	3,394	3,603	3,742	3,972
Other	**1,094**	1,051	959	944	888	857
Total electric customers	**1,482,405**	1,471,229	1,467,385	1,498,362	1,488,866	1,480,008
Operating Revenues *(Millions of Dollars)*						
Residential	**$ 1,357**	$ 1,370	$ 1,379	$ 1,371	$ 1,351	$ 1,308
Small commercial and industrial	**779**	749	730	710	679	672
Large commercial and industrial	**1,077**	1,098	1,135	1,149	1,168	1,225
Other	**148**	140	137	136	161	168
Unbilled	**19**	(26)	43	(11)	(1)	(7)
Service territory	**3,380**	3,331	3,424	3,355	3,358	3,366
Interchange sales	**59**	26	17	23	14	32
Sales to other utilities	**728**	498	334	247	233	199
Total electric revenues	**4,167**	3,855	3,775	3,625	3,605	3,597
Operating Expenses						
Operating expenses, excluding depreciation	**2,698**	2,244	2,026	2,209	1,894	1,990
Depreciation	**553**	462	431	416	401	391
Total operating expenses	**3,251**	2,706	2,457	2,625	2,295	2,381
Electric Operating Income	**$ 916**	$ 1,149	$ 1,318	$ 1,000	$ 1,310	$ 1,216
Average Use per Residential Customer *(Kilowatthours)*						
Without electric heating	**6,695**	6,771	6,908	6,736	6,727	6,259
With electric heating	**16,400**	17,946	17,189	17,527	17,096	16,298
Total	**7,830**	8,074	8,130	8,041	7,970	7,443
Electric Peak Load, Demand *(Thousands of Kilowatts)*	**7,390**	6,509	7,244	7,227	7,100	6,617
Net Electric Generating Capacity-Year-end Summer Rating *(Thousands of Kilowatts)*	**9,204**	9,201	9,078	8,956	8,877	8,836
Cost of Fuel per Million BTU	**$ 0.84**	$ 0.93	$ 0.87	$ 0.89	$ 0.90	$ 0.82
BTU per Net Kilowatthour Generated	**10,737**	10,682	10,705	11,617	10,675	10,657

Operating Statistics *(continued)*

For the Years Ended December 31,	**1997**	1996	1995	1994	1993	1992
Gas Operations						
Sales *(Millions of Cubic Feet)*						
Residential	**1,614**	1,681	1,516	1,636	1,637	1,819
House heating	**32,666**	35,471	30,698	32,246	30,242	30,218
Commercial and industrial	**19,830**	20,999	18,464	19,762	18,635	19,026
Other	**673**	2,571	1,582	7,039	9,733	4,885
Unbilled	**212**	(1,306)	1,710	(474)	676	(736)
Total gas sales	**54,995**	59,416	53,970	60,209	60,923	55,212
Gas transported for customers	**30,412**	27,891	48,531	29,801	22,946	22,060
Total gas sales and gas transported	**85,407**	87,307	102,501	90,010	83,869	77,272
Number of Customers						
Residential	**55,592**	56,003	56,533	57,122	59,573	59,859
House heating	**314,335**	303,996	295,481	287,481	277,500	269,577
Commercial and industrial	**35,215**	34,182	33,308	32,292	31,573	30,956
Total gas customers	**405,142**	394,181	385,322	376,895	368,646	360,392
Operating Revenues *(Millions of Dollars)*						
Residential	**$ 17**	$ 16	$ 15	$ 16	$ 15	$ 16
House heating	**265**	249	236	238	202	203
Commercial and industrial	**145**	133	126	128	110	113
Other	**3**	11	5	20	28	12
Unbilled	**(1)**	(4)	7	(3)	5	(1)
Subtotal	**429**	405	389	399	360	343
Other revenues (including transported for customers)	**22**	24	22	17	23	23
Total gas revenues	**451**	429	411	416	383	366
Operating Expenses						
Operating expenses, excluding depreciation	**333**	302	302	326	279	261
Depreciation	**28**	27	26	26	24	23
Total operating expenses	**361**	329	328	352	303	284
Gas Operating Income	**$ 90**	$ 100	$ 83	$ 64	$ 80	$ 82

Securities Statistics

Ratings on PECO Energy Company's securities

	Mortgage Bonds		Preferred Stock	
Agency	Rating	Date Established	Rating	Date Established
Duff and Phelps, Inc.	BBB+	4/92	BBB-	8/91
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	4/92

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

	1997				1996			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	**$ 25-1/8**	**$24-5/16**	**$ 21-1/8**	**$ 26-3/8**	$ 27-3/8	$ 26-1/4	$ 26-7/8	$ 32-1/2
Low price	**$21-7/16**	**$ 20-3/4**	**$ 18-3/4**	**$ 20**	$ 23-7/8	$ 23	$ 22-1/2	$ 26-1/4
Close	**$ 24-1/4**	**$23-7/16**	**$ 21**	**$ 20-3/8**	$ 25-1/4	$ 23-3/4	$ 26	$ 26-5/8
Earnings	**($8.51)**	**69¢**	**53¢**	**49¢**	51¢	65¢	43¢	65¢
Dividends	**45¢**	**45¢**	**45¢**	**45¢**	45¢	43.5¢	43.5¢	43.5¢

Board of Directors

Susan W. Catherwood (54)
Chairman, Trustee Board,
The University of Pennsylvania
Medical Center and Health System

Daniel L. Cooper (62)(2)
Former Vice President and General
Manager, Nuclear Services Division,
Gilbert/Commonwealth, Inc.

M. Walter D'Alessio (64)
President and Chief Executive
Officer,
Legg Mason Real Estate Services
(Commercial mortgage banking
and pension fund advisors)

G. Fred DiBona, Jr. (46)
President and Chief Executive
Officer,
Independence Blue Cross

R. Keith Elliott (55)
Chairman, President and Chief
Executive Officer,
Hercules, Inc.

Richard G. Gilmore (70)(1)
Former Senior Vice President,
Finance and Chief Financial Officer
of the Company

Richard H. Glanton, Esquire (51)(1)
Partner of the law firm Reed Smith
Shaw and McClay

James A. Hagen (65)
Former Chairman, Conrail, Inc.

Admiral Kinnaird R. McKee (68)
Director Emeritus,
U.S. Navy Nuclear Propulsion

Joseph J. McLaughlin (69)(1)
Former President and Chief
Executive Officer,
Beneficial Mutual Savings Bank

Corbin A. McNeill, Jr. (58)(1)
Chairman of the Board,
President and Chief Executive
Officer of the Company

John M. Palms, PhD. (62)
President,
University of South Carolina

Joseph F. Paquette, Jr. (63)(1)
Former Chairman of the
Board of the Company

Ronald Rubin (66)(1)
Chief Executive Officer,
The Rubin Organization, Inc.
(Real estate development and
management)

Robert Subin (59)
Senior Vice President,
Campbell Soup Company

Officers

Corbin A. McNeill, Jr. (58)
Chairman of the Board,
President and Chief Executive
Officer

Dickinson M. Smith (64)
President, PECO Nuclear
and Chief Nuclear Officer

Gregory A. Cucchi (48)(3)
Senior Vice President,
Ventures

James W. Durham (60)
Senior Vice President, Legal and
General Counsel

Michael J. Egan (44)(4)
Senior Vice President, Finance
and Chief Financial Officer

William J. Kaschub (55)
Senior Vice President,
Human Resources

Kenneth G. Lawrence (50)(4)
Senior Vice President,
Local Distribution Company

John M. Madara, Jr. (54)
Senior Vice President,
Power Generation Group

William H. Smith, III (49)(5)
Senior Vice President,
Business Services Group

Alvin J. Weigand (59)
Senior Vice President

Gerald R. Rainey (48)
Senior Vice President,
Nuclear Operations

Nancy J. Bessey (44)
Vice President,
Power Transactions

John B. Cotton (53)(6)
Vice President,
Station Support

John Doering, Jr. (54)
Vice President, Operations,
Power Generation Group

Gregory N. Dudkin (40)(3)
Vice President,
Power Delivery

Drew B. Fetters (46)
Vice President,
Nuclear Planning and Development

Thomas P. Hill, Jr. (49)
Vice President and Controller

Cassandra A. Matthews (47)(7)
Vice President,
Information Systems

John P. McElwain (47)(6)
Vice President,
Nuclear Projects, PECO Nuclear

J. Barry Mitchell (50)
Vice President,
Finance and Treasurer

Thomas N. Mitchell (42)
Vice President,
Peach Bottom Atomic Power
Station

William E. Powell, Jr. (61)
Vice President,
Support Services

James D. von Suskil (51)(8)
Vice President,
Limerick Generating Station

Katherine K. Combs (47)
Corporate Secretary

Edward J. Cullen, Jr. (50)
Assistant Corporate Secretary

Todd D. Cutler (37)
Assistant Corporate Secretary

Diana Moy Kelly (43)
Assistant Treasurer

George R. Shicora (51)
Assistant Treasurer

(1) Member of the Executive Committee of the Board of Directors
(2) Elected June 23, 1997
(3) Effective June 1, 1997
(4) Effective October 13, 1997
(5) Effective November 7, 1997
(6) Effective April 9, 1997
(7) Effective July 28, 1997
(8) Effective January 26, 1998

Stock Exchange Listings

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

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 $1.80 per share dividend paid to common shareholders in 1997 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 1997, over 55 percent of the Company's common shareholders were participants in the Plan. Information concerning the Plan may be obtained from: First Chicago Trust Company of New York, 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: First Chicago Trust Company of New York, P.O. Box 2500, Jersey City, NJ 07303-2500.

Toll-Free Telephone

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

Annual Meeting

The Annual Meeting of the Shareholders of the Company will be held at the Valley Forge Convention Center in King of Prussia, Pennsylvania on April 8, 1998 at 9:30 AM. The record date for voting at the shareholders' meeting is February 20, 1998. Prompt return of proxies will be appreciated.

Form 10-K

Form 10-K, the annual report filed with the Securities and Exchange Commission, is available without charge to shareholders upon written request to PECO Energy Company, 2301 Market Street, P.O. Box 8699, Philadelphia, PA 19101-8699, Attention: Investor and Shareholder Relations Division, S21-1

Shareholders

The Company had 163,049 shareholders of record of common stock as of December 31, 1997.

Transfer Agents and Registrars

Preferred and Common Stock Registrar and Transfer Agent:
First Chicago Trust Company of New York, P.O. Box 2500, Jersey City, NJ 07303-2500.

First and Refunding Mortgage Bond Trustee:
First Union National Bank, Corporate Trust Operations,
Customer Information Center
1525 West W.T. Harris Blvd.
Charlotte, NC 28288-1153

New York Agent for bonds:
First Trust of New York, National Association Corporate Trust Department, 100 Wall Street, Suite 1600, New York, NY 10005.

Internet Site

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

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Philadelphia, Pennsylvania 19103
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PECO ENERGY

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