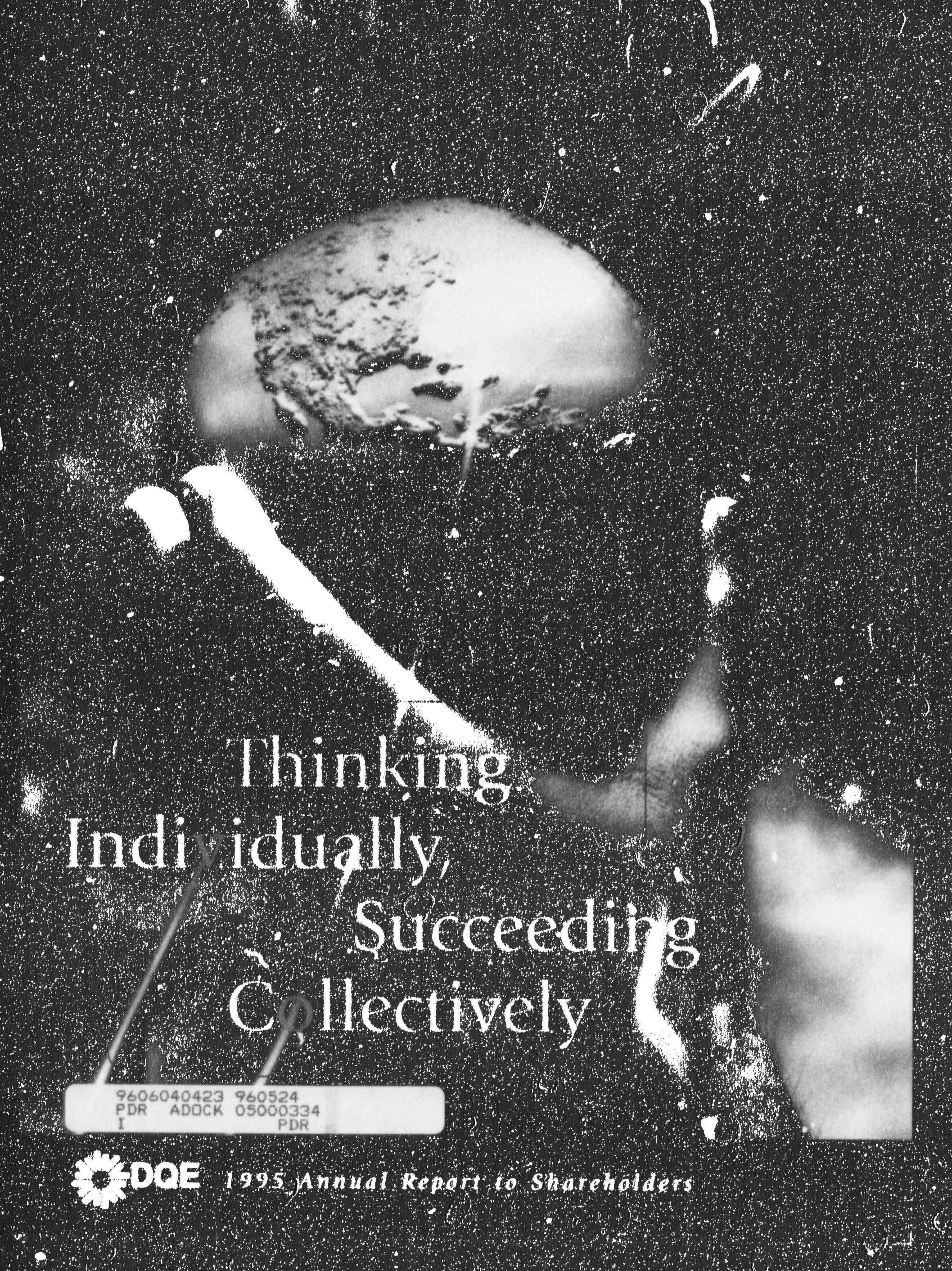


Thinking Individually, Succeeding Collectively

DQE 1995 Annual Report to Shareholders

Corporate Profile

DQE is an evolving energy services company that is strategically positioning itself to meet the expanding energy needs of the marketplace.

1995 Results

- *DQE earnings per share increased by 11% from 1994.*
- *Duquesne Light's system peak demand of 2,666 megawatts was its highest ever.*
- *Duquesne Light established a new record for customer energy use in a single month — 1.4 billion kilowatt-hours in August.*
- *Three Duquesne Light environmental projects — the company's youth education programs, enhancement of a wildlife habitat at Brunot Island Power Station, and the innovative disposal of fly ash in abandoned mines — have been selected to appear in Renew America's Environmental Success Index.*
- *Duquesne Light established new records for the shortest refueling outage at both of the nuclear generating units it operates.*
- *Duquesne Enterprises and Montauk contributed 32 cents to earnings per share, an increase of 50% over 1994.*
- *Duquesne Enterprises made strategic investments to enhance DQE's capabilities as an energy services provider.*
- *Montauk made investments to better diversify its investment portfolio and position itself for future earnings growth.*
- *DQE Energy Services was formed in August 1995.*

Contents

Some statements in this report are forward-looking statements that involve risks and uncertainties, including, but not limited to, the effect of economic conditions, the impact of competition, the effect of the company's accounting policies, and other risks detailed in the company's Securities and Exchange Commission filings.

DQE Financial and Operating Highlights

(millions)	1995	Change From 1994	1994	Change From 1993	1993
Electric Customer Sales	12,428 KWH	2.5%	12,122 KWH	2.3%	11,851 KWH
Operating Revenues	$1,220	-0.3%	$1,224	3.5%	$1,183
Non-Fuel Operating and Maintenance Expense	$384.7	-5.7%	$408.0	-0.1%	$408.4
Operating Income	$322.5	1.8%	$316.9	1.2%	$313.0
Interest and Other Charges	$107.6	-2.2%	$110.0	-8.1%	$119.7
Net Income	$170.6	8.8%	$156.8	8.9%	$144.0
Year-End Shares Outstanding	77.6	-1.1%	78.5	-1.3%	79.5
Net Operating Cash Flow (A)	$378.9	1.0%	$375.2	-3.1%	$387.4
Capital Expenditures and Other Investments	$281.9	50.1%	$187.8	-4.3%	$196.3
Return on Average Common Equity	13.1%		12.5%		12.0%
Average Cost of Fuel Per KWH Generated	1.39¢	-3.5%	1.44¢	-4.0%	1.50¢
Average Cost of Generation Per KWH (B)	2.22¢	-0.5%	2.23¢	-4.3%	2.33¢
Peak Demand	2,666 MW	5.2%	2,535 MW	1.4%	2,499 MW

KWH: Kilowatt-hour. A measure of the quantity of electricity consumed in one hour, equivalent to 1,000 watts consumed in one hour.
MW: Megawatt. A measure of the electric generating capacity of power plants, equal to 1,000 kilowatts.
(A): Excludes working capital and other balance sheet changes.
(B): Excludes capital cost.

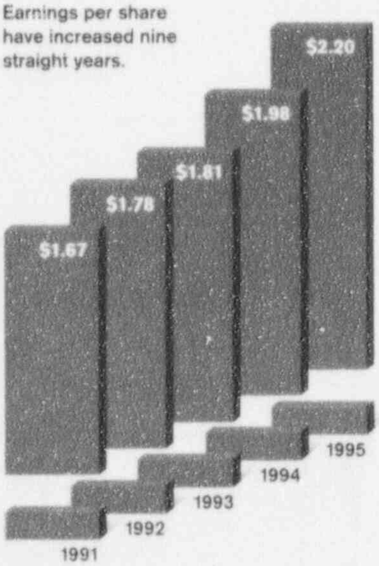
COMMON STOCK TRENDS

	1995	1994	1993	1992	1991	1990	Five-Year Compound Growth Rate
Earnings Per Share	$2.20	$1.98	$1.81	$1.78	$1.67	$1.49	8.1%
Dividends Paid Per Share	$1.19	$1.12	$1.07	$1.01	$ .96	$ .91	5.5%
Book Value at Year-End	$17.13	$16.27	$15.47	$14.75	$14.00	$13.38	5.1%
Market Price Per Share							
High	$30.75	$23.00	$24.67	$21.58	$20.67	$16.83	12.8%
Low	$19.63	$18.42	$20.92	$17.92	$15.75	$13.58	7.7%
Year-End	$30.75	$19.75	$23.00	$21.50	$20.42	$16.58	13.2%

All amounts have been restated for the 3-for-2 stock split declared in April 1995.

DQE Earnings Per Share

Earnings per share have increased nine straight years.



Year-End Annualized Dividends Per Share

Dividend growth has been in the top quartile of the industry.

Even as the energy services industry continues to evolve, DQE is providing exceptional value to you, our shareholders. *We are achieving this success through a number of innovative strategies that build upon the strength of our core business and grow our company through new, market-driven business opportunities.* This report details the breadth of a company that focuses on energy solutions for customers.

In the photo stories on the following pages, we share with you some of the motivated and dedicated people who are finding opportunity in the changes taking place in our industry and at DQE. Summarized in these stories are highlights of the year, which include significant operating improvements at our core utility business as well as the increased importance our market-driven investments have had on our earnings performance. Following are some of the major breakthroughs for you as a shareholder:

Wes von Schack

Financial Performance

- A three-for-two stock split increased the number of shares you own by 50 percent and made it easier for individual shareholders to add to their investment in our company.
- DQE has provided you with one of the best total returns in the industry over the past five years.

Environmental Leadership

- Development and implementation of new power station burner technology that reduced nitrogen oxide emissions, meeting stringent regulatory requirements at a moderate cost.
- Chester Engineers' volume of international work resulted in receipt of the Pennsylvania Governor's Export Excellence Award.

Customer Service Superiority

- Duquesne Light became the first Pennsylvania regulated utility and one of the first utilities in the nation to offer its residential customers comprehensive guarantees of its commitment to courteous, reliable and efficient service.

Looking to the future, we have taken steps to distinguish our core business in the energy services industry from that of our competitors.

In late 1995, Duquesne Light announced several broad-based customer initiatives that continue its transition to competitive electric energy markets and target the highest levels of guaranteed customer service in the industry.

Duquesne Light's plan to freeze base rates for five years for all customers would result in a 40 percent inflation-adjusted price reduction in the decade of the 1990s. Also included in the plan is a proposed $5 million annual credit to customers through the utility's fuel clause.

This initiative is predicated on regulatory approval of the sale of Duquesne Light's 50 percent interest in Unit 1 of the Fort Martin Power Station. The sale of an asset that we no longer need for baseload capacity underscores Duquesne Light's commitment to provide its customers with the highest level of operational efficiency. The proceeds from the sale will be used to further restructure Duquesne Light's balance sheet.

A final measure in this plan is a recommendation to both the Pennsylvania Public Utility Commission and the Federal Energy Regulatory Commission that Duquesne Light, Allegheny Power System and Penn Power, along with companies in the existing Pennsylvania-New Jersey-Maryland (PJM) power pool, be admitted to a new regional pool, and that this pool be operated as an independent transmission company through which all wholesale electricity would be sold under common terms at market prices.

Another important customer service initiative is Duquesne Light's Customer Advanced Reliability System, which is a state-of-the-art communications link through the electric meter that will provide customers with superior levels of service reliability, security and convenience. The addition of this capability will raise the standard for customer service to a new threshold because utility personnel will be able to respond to customer needs on the basis of immediate, real-time information about the status of power delivery at individual homes and businesses.

This new communications service is another major element in our multi-step plan to make our utility business more competitive and efficient. The Customer Advanced Reliability System's ability to process information about power delivery will provide customers with new choices and greater convenience, and enable Duquesne Light to more effectively manage its electric power load growth profile.

By capitalizing on the strengths of our core business — a solid, well-balanced sales mix; improved operating efficiencies; decreased production costs; and stabilized rates — we are positioning ourselves for growth in a competitive energy services market.

Our market-driven businesses have played an increasingly important role in this positioning. Montauk, a financial services company, continues to be the most significant contributor to earnings. During 1995, Montauk invested in high credit-quality opportunities that enhanced our investment portfolio balance. The returns on these investments are anticipated to enable Montauk to continue its solid earnings growth trend. Our other market-driven businesses, Duquesne Enterprises and DQE Energy Services, are providing energy solutions for customers as they seek new opportunities related to the core business.

> The incremental steps we have taken over the past several years have created a more efficient, more competitive, more market-driven and more profitable company.

These results illustrate how people at DQE have thought individually and succeeded collectively. The incremental steps we have taken over the past several years have created a more efficient, more competitive, more market-driven and more profitable company. Through these measured steps, we believe DQE is strategically positioning itself for a competitive electric power market and for the growing energy services marketplace. *The industry is facing a tremendous amount of uncertainty. Changing, and at this point unknown, state and federal regulations and new technologies will clearly influence the future of energy services providers.* We firmly believe that the strategies we have embraced in recent years are the right ones.

We thank you for your continued support.

On behalf of the Board of Directors,

Wes Von Schack

Wesley W. von Schack
Chairman and Chief Executive Officer
February 26, 1996

Duquesne Light Company

Business Description

Duquesne Light Company, whose origin dates to 1880, is engaged in the production, transmission, distribution and sale of electric energy. Its service territory is approximately 800 square miles in southwestern Pennsylvania, with a population of 1.5 million, located within a 500-mile radius of one half of the population of both the United States and Canada. In addition to serving more than 580,000 direct customers, the company sells electricity to other utilities.

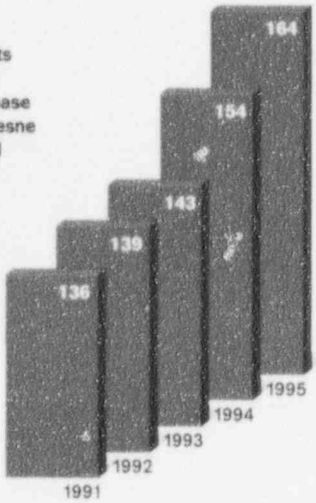
1995 Operating Highlights

- Both company-operated nuclear generating units achieved record refueling outages in terms of number of days needed for completion
- Introduced one of the first comprehensive customer service guarantee programs in the nation
- System peak demand of 2,666 megawatts was the company's highest ever
- Received Edison Electric Institute's Diversity-Affirmative Action Award for the second year in a row

Outlook

- Broad-based customer initiatives proposed to the Pennsylvania Public Utility Commission include a five-year rate freeze and sale of the company's interest in Fort Martin Power Station. The rate freeze, to begin in 1996, would result in a 40-percent, inflation-adjusted price reduction in the decade of the 1990s
- The Customer Advanced Reliability System, a state-of-the-art electronic communications link with individual customers through the electric meter, will provide superior levels of service reliability, security and convenience
- Cost reduction has enabled increased capital recovery in an effort to lower fixed generation costs and better position the utility for increasing competition

Customers Served Per Employee



Efficiency improvements during the 1990s have resulted in a 20% increase in the number of Duquesne Light customers served per employee.

Duquesne Enterprises

Business Description

Duquesne Enterprises makes strategic investments beneficial to DQE's core energy business. These investments enhance DQE's capabilities as an energy provider, increase asset utilization and act as a hedge against changing business conditions. Duquesne Enterprises' investments include:

- Allegheny Development Corporation, a subsidiary which provides all energy services for the Pittsburgh International Airport
- Property Ventures, Ltd., a subsidiary which owns and develops real estate in southwestern Pennsylvania
- Exide Electronics Group, Inc., an integrated provider of non-interruptible power quality products, systems and services, both domestically and internationally
- Chester Engineers, a subsidiary which is a leading domestic and international water and wastewater engineering and services company
- RECRA Environmental, one of the largest environmental testing and measurements companies in the United States

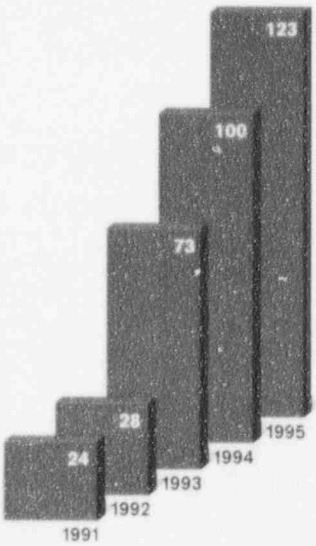
1995 Operating Highlights

- Exide's acquisition of International Power Machines Corporation resulted in a (post-split) 5 cents per share gain
- Chester Engineers won the Pennsylvania Governor's Export Excellence Award
- Property Ventures' involvement in Duquesne Light's move to new corporate headquarters, which substantially reduced the utility's rental costs

Outlook

- Continued developments with existing subsidiaries and new opportunities related to the core business
- Future initiatives are expected to include fuel cells, energy consultant services and telecommunications businesses

Duquesne Enterprises Assets
(at Dec. 31, millions of dollars)



Montauk

Business Description

Montauk is a financial services company that makes long-term investments and provides financing to market-driven business activities.

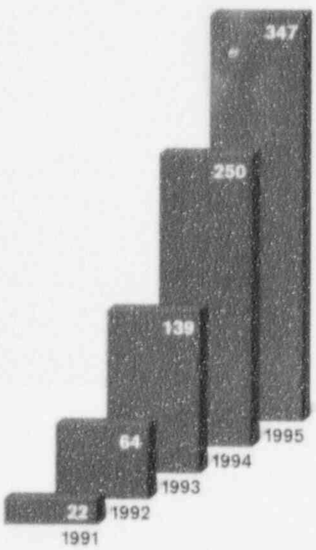
1995 Operating Highlights

- 36% increase in net income
- Increased investment portfolio diversity by geographic region and investment type
- Enhanced liquidity of market-driven enterprises through financing activities

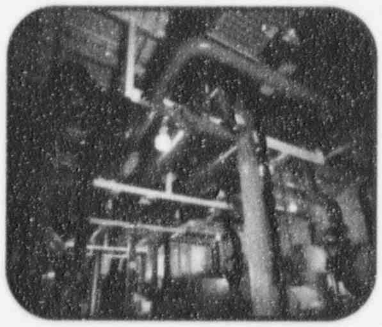
Outlook

- Continue to support DQE's initiatives to provide high-quality products, services and solutions to energy customers
- Continue to maintain a diversified portfolio of high credit-quality investments to minimize risk
- Access new investment opportunities related to areas of expertise, including fee-based and consulting initiatives
- Continue to be a source of financing for market-driven activities, providing expertise in the project finance area for DQE Energy Services activities

Montauk Assets
(at Dec. 31, millions of dollars)



DQE Energy Services



Business Description

DQE Energy Services is a marketing and development company providing energy solutions for customers in domestic and international markets. Included are energy facility development and operation, independent power production, gas and electric energy/fuel management, utility management services and advanced systems.

1995 Operating Highlights

- Formed in August 1995
- Formed a joint venture with Marathon Oil, ElectroGen International, which will develop, own and operate power generation projects in selected international markets

Outlook

- Develop, own and operate domestic energy facilities
- Develop, own and operate power generating facilities in international markets
- Develop and market selected utility services to domestic and international customers
- Initiate strategic partnerships to market innovative energy/fuel management programs

EGI
ElectroGen
INTERNATIONAL

Joint venture formed by DQE Energy Services and Marathon Oil to pursue international power projects.

As the idea of electric utility industry restructuring germinated in the late 1980s and gained increasing momentum in the 1990s, we accelerated the transformation of our company to meet increasing competition. Our utility operations featured 100-plus years of quality customer service and technical innovation. With the formation of the holding company structure in 1989, we gained the flexibility to pursue new business opportunities related to our core business. Driving this transformation into a dynamic, global energy services company is a combination of entrepreneurism and teamwork. DQE is a company whose people understand the need for change to successfully compete in the increasingly competitive energy marketplace, and who are working together to provide exceptional shareholder value. As the photo stories on the following pages demonstrate, we are

Thinking Individually, Succeeding Collectively

Strong Financial Performance

During the 1990s, DQE has provided investors with one of the top total returns in the industry. In 1995 we continued our strong performance.

Shareholders again benefited from per share increases in earnings and dividends. These solid financial results reflect the continued evolution of our company. Managing this transition are individuals with perceptive leadership abilities who have brought decision-making in all of our businesses closer to the customer level.

The customer-service focus and cost-control efforts of Duquesne Light Company have provided the foundation for our strong financial performance. However, our recent earnings growth has resulted as much from the growth of market-based enterprises as from our core utility business.

DQE's market-driven subsidiaries — Duquesne Enterprises, Montauk, and DQE Energy Services — provided 32 cents per share to earnings in 1995, compared to 21 cents per share in 1994 and 9 cents per share in 1993. While Duquesne Light continues to be a fully integrated provider of electricity to the greater Pittsburgh region, future growth will come from the sale of new products and services related to our core business. These initiatives, being developed and implemented through our market-driven subsidiaries, will provide energy solutions to customers both inside and outside of the utility's traditional service territory.

Lydia York

Vice President, Montauk

This 6,000-ton cross-pit spreader system moves mountains of earth so Texas Utilities Mining Company can more economically harvest deep-seam lignite coal. Lydia York (left) sifts through mountains of potential investment ideas to find those, like the cross-pit spreader, that will achieve solid returns for our shareholders. Investments selected by Montauk are closely related to our core business, are geographically diverse (47 states, 2 foreign countries), are not concentrated in one type of business (43% leasing, 34% affordable housing, and 23% oil and gas) and are made with high credit-quality companies. While Lydia works long hours, she can't quite match the cross-pit spreader. It operates around the clock, 365 days a year. And you'll be pleased to know that Texas Utilities' land reclamation program has won national and state honors. In fact, many of its procedures have been used as models for federal regulations.

Weather Warms Utility Sales

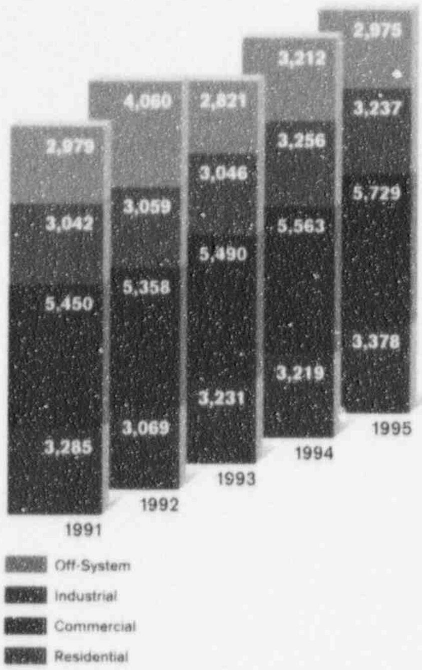
During 1995, sales of electricity to Duquesne Light's direct customers increased more than two percent from the 1994 level. Warmer-than-normal summer temperatures resulted in a higher level of sales to residential customers. Warmer temperatures were a lesser but contributing factor to continuing higher sales to commercial customers.

Duquesne Light has a well-balanced sales mix. Commercial sales represent almost 38 percent of total 1995 kilowatt-hour sales. The rest of the utility's sales mix is evenly balanced between residential, 22 percent; industrial, 21 percent; and sales to other utilities, 19 percent.

During the 1990s, the residential customer base has remained stable. Even with continued customer interest in efforts to promote the comfort, convenience, safety and lifestyle improvements afforded by electric living, future residential sales fluctuations will continue to be mainly dependent upon weather.

Commercial sales have been a consistent growth sector, increasing in 15 of the past 16 years, even when weather variations are considered. Diversification of the Pittsburgh region and Duquesne Light's economic development initiatives have driven this growth. Spurred by further

Electric Utility Customer Sales
(millions of kilowatt-hours)



Sales mix remains balanced.

marketing efforts and customer satisfaction enhancements, we expect commercial sales to continue to be the utility's main source of future electric sales growth.

Unlike many utilities, Duquesne Light's sales are diverse, with industrials being the smallest direct market segment. And despite the trend toward large consumption customers changing their supplier of electricity or fully generating their own power supply, Duquesne Light has not lost any existing major customers to other energy providers. In fact, late in the year, the utility signed five-year energy contracts with a major retailer and an international food manufacturer.

As restructuring of the electric utility industry continues, off-system sales to other utilities will become more significant. The biggest impediment to a long-term power sale of Duquesne generation has been obtaining access to the transmission grid owned by other utilities. Applications have been filed with the Federal Energy Regulatory Commission (FERC) for transmission service from other utilities. FERC authorized this access for Duquesne Light, but the utility has been unable to receive comparably priced terms for this service. The matter is pending before FERC. Gaining transmission access would enhance our ability to negotiate long-term sales agreements with other utilities.

Taking Charge of Change

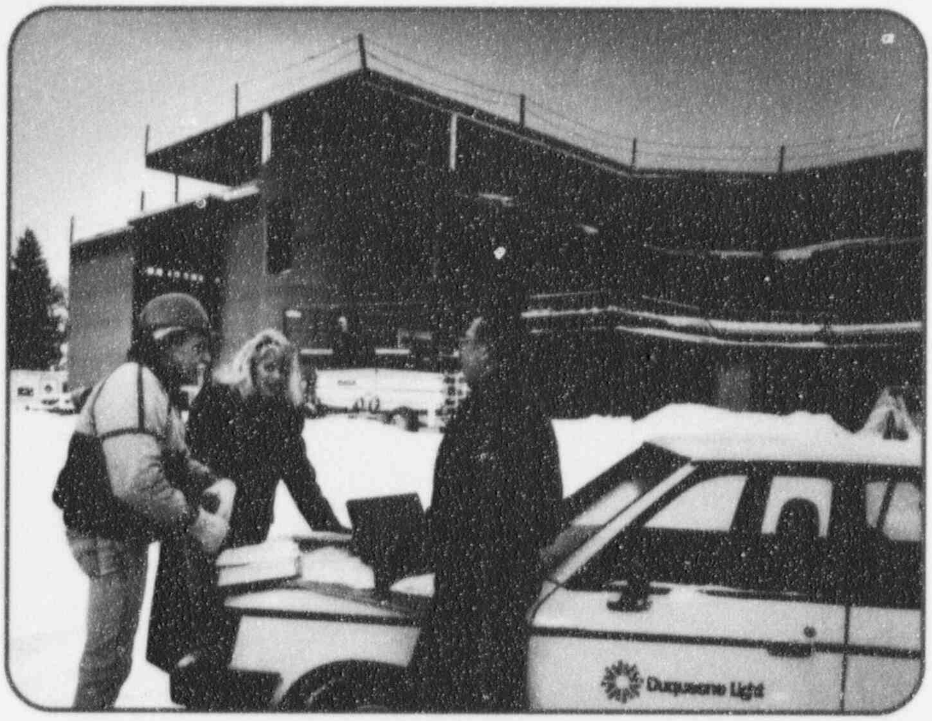
Inherently, utility sales are influenced by external factors, such as weather and the economy. With impending deregulation and the resulting increases in competition, we have been taking steps to ensure that future sales will be influenced to a greater degree by internally controllable factors, such as service reliability, customer satisfaction initiatives and pricing. Duquesne Light has the programs in place, and the individuals managing and executing them, to excel in these critical areas.

Duquesne Light has reduced its residential prices by almost 13 percent since 1991. Relative to the rising prices of other goods and services in the region during that period, Duquesne Light customers have seen a decline in the real

Malcom Bynum

Field Service Representative, Duquesne Light

Duquesne Light is one of only a handful of U.S. electric utilities to offer a comprehensive customer service guarantee program. The utility will provide a $25 credit to a customer's monthly bill in the event it does not deliver courteous, timely and accurate results in the areas of service connections, service visits and billing. Thanks to the initiative and professionalism of people like Malcom Bynum (see photo), the error rate has been an impressively low .007% in more than 17 million transactions.



Throughout our utility operations, we are increasing efficiency by combining job classifications, using new technology and re-engineering work processes. Peg Page (below) led a team dedicated to streamlining Duquesne Light's procedures for providing a new or upgraded service connection for residential and commercial customers. The team's goal was to make the procedure a one-call, one-stop process. Using a Telepad portable computer, a technician, like Andy Vidra (above, right), now can provide customers a simple service connection design drawing and a cost estimate in the field. Computerization of the process allows new-business managers like Patty Tuite (above, center), who coordinate the process, to be able to give customers immediate job status updates. The streamlined system also gives customers more options, because the people who deal with them directly have increased authority to make decisions on the spot.

Peg Page

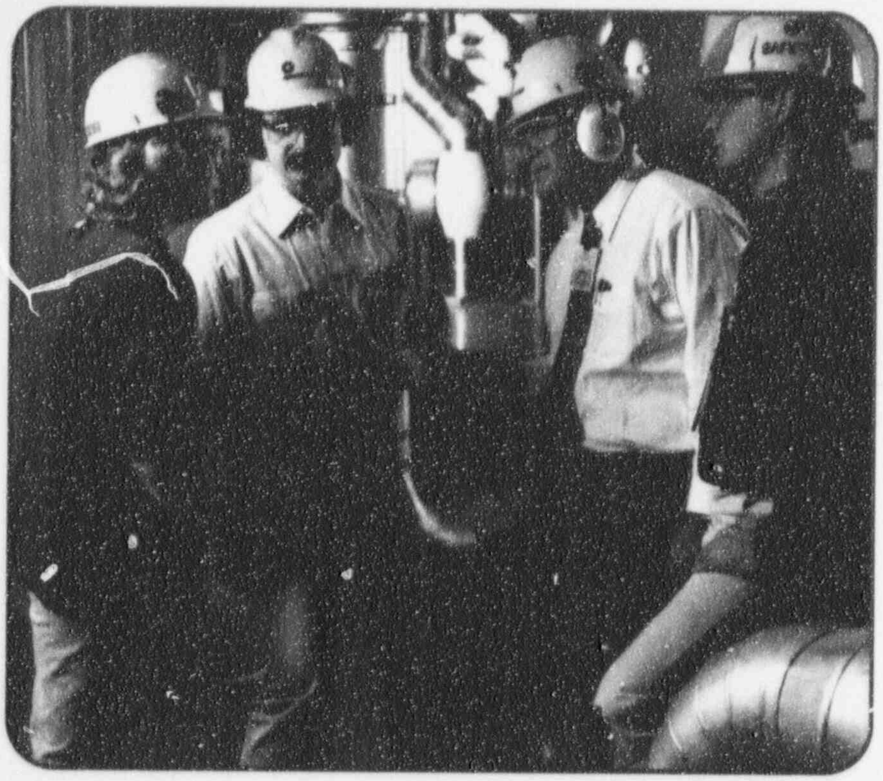
Director, Product Integration, Duquesne Light

cost of electricity of approximately 25 percent. Late in 1995, the utility announced a proposal to freeze prices through the year 2000. If granted by the Pennsylvania Public Utility Commission (PUC), the rate freeze would result in a 40 percent inflation-adjusted price reduction during the decade of the 1990s. Currently, industrial customer prices are competitive with regional averages, in part because of the PUC's support of innovative, flexible economic development pricing by Duquesne Light within its service territory. The utility offers manufacturing customers that locate new business in its territory a price for power competitive with any electric utility in Pennsylvania. Current customers considering expansion, for whom electricity is a significant cost factor, receive a similar guarantee. Duquesne Light will commit to a cost of electric service that is competitive with alternative expansion anywhere in Pennsylvania.

Telepad portable computer

When direct retail competition arrives, customers in a free market will continue to seek out value. Value comes in many forms: from energy solutions that can improve a company's operation or an individual's lifestyle, to guaranteed levels of customer service.

In 1995, Duquesne Light introduced one of the first comprehensive customer service guarantee programs in the nation (see photo page 8). The utility guarantees that customer bills will be accurate; that service representatives will arrive for appointments on time; that customers will receive prompt, courteous and professional service; and that new residential service will be connected within one day of the date requested by the customer. In the event that Duquesne Light does not meet



Jim Cross

Senior Vice President and Chief Nuclear Officer, Duquesne Light

Jim Cross (second from right) is a nuclear industry veteran, with 25 years of experience at generating stations in Florida, Tennessee, Mississippi and Oregon. He joined Duquesne Light in 1994. By encouraging teamwork, reducing the number of outside contractors and requiring high performance standards, his impact has quickly been felt at Beaver Valley Power Station. Both of its units achieved their best-ever refueling outage times in 1995. Reducing outage time not only saves money, it also increases output, meaning the station can produce more electricity at a much lower, more competitive cost. Jim is pictured here with (from left) Debbie Reid-Lees of Maintenance and Sam Checketts and Scott Cencic of Operations.

expectations in these four guarantee areas, $25 is credited to the customer's account. In the first year of the program, the error rate has been less than one hundredth of one percent in more than 17 million customer transactions.

Duquesne Light traditionally has made a special effort to adapt new technologies to its basic customer service operations. It has one of the most automated distribution systems of any utility. Duquesne Light's expansive communications network enables it to pinpoint service interruptions and automatically switch loads and sectionalize circuits. That enables the utility to spot and isolate problem areas so it can minimize the number of customers affected by a storm and respond promptly to areas that are without service.

Over the next few years, the utility will be implementing a number of initiatives that fundamentally will change the way it does business so it can continue to enhance customer satisfaction levels that already are among the best in the industry.

A state-of-the-art communications service of Itron, Inc., to be installed during the next two years, will provide Duquesne Light's residential customers with superior levels of service reliability, security and convenience. Itron, a leading supplier of energy information and communication solutions to the utility industry, will own and operate a two-way wireless communication network that will provide a link through the electric meter to Duquesne Light's 580,000 customers. The Customer Advanced Reliability System will provide a variety of valuable information. Electric use will be recorded immediately and communicated electronically to a control center at the utility. As a result, customer service personnel will have a real-time picture of the status of power delivery across the system and for individual customers. If a customer loses power for any reason, the utility will know about it. The customer will not have to report the outage, and Duquesne Light's efforts to restore power can begin sooner, reducing the time the customer is without power. Customers also will be able to request electric service to start or stop on any hour of any day. And customers who have electric meters inside their homes no longer will have to provide access to have their meters read.

In the future, Duquesne Light will be able to profile each customer's consumption of electricity. Coupled with time-of-use and other special rates, this information will help customers realize more value from

their use of electricity. As the transition to competition and customer choice begins over the next decade, Itron's technology will enable the utility to implement the needed metering and billing services. The first Duquesne Light customers will be connected to the new system in April 1996, and all customers will be on-line in 1997.

We view our long-standing environmental commitment as another competitive advantage. Surveys show that an increasing number of consumers place value on a company's environmental performance. Through the years, we have earned a reputation as an environmental leader in our industry. The photo below details one of our recent success stories in this important area. Our commitment is driven by our environmental strategic plan, which stresses compliance, training, issues management, stewardship and communications. Through our comprehensive and innovative approach to environmental excellence in our operations and our community stewardship programs, we continue to expand that commitment.

Cost Reductions Building Value

As utility competition increases, so does the importance of cost control. Duquesne Light had another successful year in this area in 1995. During the year, the Beaver Valley Power Station nuclear generating units both had record refueling outages in terms of the number of

NO_X Reduction Project Team

— Duquesne Light

A true team effort solved a potentially expensive environmental challenge, made one of Duquesne Light's coal-fueled plants more competitive, put the company in contention for the industry's highest honor, and helped the utility win another major industry award for the second year in a row. People from fossil generation, environmental affairs, engineering and purchasing joined in a creative partnership with Energy Systems Associates to develop new burner technology that is helping Duquesne's Elrama Power Station meet stringent Clean Air Act regulations for nitrogen oxide (NO_X) emissions at a fraction of the cost of solutions being used by other utilities. In fact, their unique approach has been patented and is attracting interest from other energy generators. The Elrama project is a finalist for the prestigious Edison Award, presented by the Edison Electric Institute (EEI) to recognize "distinguished leadership, innovation and contribution to the advancement of the electric industry." The work of the diverse, multi-disciplinary task team that developed and perfected the new technology also was cited in Duquesne Light's receipt of EEI's Diversity-Affirmative Action award for the second year in a row. Project team members include (top row, from left) Bob Orchowski, Michael Skoncey, James Breslin, (middle) Joe Cavello, Mel Crigler, Rick Sarver; (bottom) Tony Hallo, Bernard Breen of Energy Systems Associates, Sharon Stubbs and Gerry Gretz.

As part of its ongoing commitment to reduce costs, Duquesne Light was looking for a new location for its corporate headquarters in downtown Pittsburgh. Don Morine of Property Ventures, Ltd. liked the location, character, soundness, and, most importantly, price of the former Chamber of Commerce Building (below). It was a good match. Duquesne Light, which completed its relocation in December 1995, has substantially reduced its rental costs while maintaining a corporate presence in its traditional Pittsburgh home base. Don is shown here (right) with Sateria Venable, an architectural engineer with Duquesne Light, inspecting a portion of the utility's new offices. Sateria was part of the team that designed the interior office environment, highlighting the historical charm of the building, which was built in 1916. The refurbished 411 Seventh Avenue has received a number of awards, including the Pittsburgh History & Landmarks Foundation Award for extraordinary restoration and adaptive re-use of a historic building, and the Pittsburgh Chapter of the American Institute of Architects Design Award for 1995. The refurbishing project was a finalist in the Master Builders Association 1995 Building Excellence Awards for renovation. The building is a fitting new neighbor to Pittsburgh's Cultural Trust District.

Don Morine
President, Property Ventures, Ltd.

Sateria Venable
Architectural Engineer, Duquesne Light

days needed for completion. As detailed in the photo caption on page 10, the men and women who operate the station plan to improve on these levels in future outages. Re-engineering of business processes, multicrafting at power stations and continued efficiency improvements across the utility during the 1990s have resulted in a 20 percent increase in the number of customers served per employee. Additionally, annual utility operation and maintenance expenses, excluding energy costs, have been reduced by more than $10 million in the past two years.

Energy costs also have been a major focus of Duquesne Light's cost reduction efforts, since they represent approximately 40 percent of the utility's variable costs. Energy costs were lower in 1995 — the third time in the last five years. The utility's delivered cost of coal is among the lowest in Pennsylvania. Its nuclear fuel cost has been reduced by 36 percent during the last five years. With these and other cost reductions, Duquesne was able to lower its variable production costs by 12 percent during the 1990s.

Market-Driven Activities Complement Core Business

With increasing competition in the energy services industry will come increasing business opportunities. DQE has been positioning itself to take advantage of these opportunities through exceptional service reliability, favorable pricing designs, efficient operations, available cash flow and, ultimately, growth through pursuit of market-driven business opportunities. Our strategy has been to stay focused on the energy services industry and to develop products and services that are complementary to our core business. Continued prudent investment in

competition-created opportunities — and their success — will continue to distinguish DQE from our competition in the future.

Our Duquesne Enterprises subsidiary is forming strategic alliances to offer a broad range of energy products and related services. During 1995, it acquired a substantial interest in Exide Electronics Group, an integrated provider of power protection and power management systems, and is exploring opportunities in fuel cells and telecommunications.

Chester Engineers, a leading national and international water and wastewater engineering and services firm, is another DE investment. Chester designs, builds, owns and operates water and wastewater treatment facilities for industrial and municipal clients, including more than 100 Fortune 500 companies. A strategic decision to pursue international markets more aggressively in the early 1990s led to significant contracts in Taiwan, Mexico, South America and China. Since our affiliation with Chester in 1993, the company has focused on expanding its core business of domestic and international water treatment consulting, while continuing to improve its profitability.

Allegheny Development Corporation has been providing all of the energy services to

"Chester Engineers has earned a reputation as a firm that can efficiently deliver water and wastewater management services anywhere in the world," said John Lucey, Jr., president and chief operating officer. Chester's complete range of turnkey engineering, construction and long-term plant operation services help businesses and communities worldwide realize continuing value from their water supplies. A burgeoning world market and the continuing growth of developing nations have opened up a wealth of opportunities for Chester in countries such as China, Mexico, Taiwan, Poland, Venezuela, Columbia and Brazil. The firm's international sales increased from $170,000 in 1992 to more than $12 million in 1994, earning Chester Pennsylvania's 1995 Governor's Export Excellence Award.

John Lucey, Jr.

President and Chief Operating Officer, Chester Engineers

Tony Lisanti

Vice Chairman and Chief Executive Officer, Chester Engineers

John Welch

Executive Vice President, DQE Energy Services

Lex Tsaggaris

President, DQE Energy Services

As the energy services industry enters a new era of change, business opportunities will continue to emerge. Energy entrepreneurs like Lex Tsaggaris (above, right) and John Welch (above, left), president and executive vice president, respectively, of DQE Energy Services, are seeking growth opportunities that provide energy solutions for customers and are complementary to our core business. They bring well-matched experiences to the job. Lex served as an officer in the Navy's nuclear submarine program, worked in the electric utility industry, and managed engineering and construction businesses. John has an extensive background in energy services management and in all aspects of the natural gas industry.

the new Pittsburgh International Airport since it opened in 1992, after winning a competitively bid contract.

Property Ventures, Ltd. acquired and refurbished a building adjacent to Pittsburgh's Cultural District, which now is serving as Duquesne Light's corporate headquarters, substantially reducing the utility's rental costs (see photo caption on page 12).

Through our Montauk subsidiary, we are the lessor in several energy-related leasing transactions, including a fossil generating station, a gas processing facility and coal mining equipment (see photo on page 6). Montauk also is a financial partner in several oil and gas production partnerships. The earnings growth trend from our market-driven businesses is expected to continue in the future as these and similar investments continue to be profitable, and as our newest subsidiary, DQE Energy Services (DES), develops.

DES was formed in August 1995 to provide innovative energy solutions for domestic and international customers, including energy/fuel management, energy facility development, co-generation, independent power production, utility management services, and advanced energy systems. This new venture is being led by two veterans of the engineering and energy services fields (see photo). Soon after its inception, DES formed a joint venture with Marathon Oil, an experienced energy company with global reach, to develop independent power production facilities abroad.

Energy Entrepreneurs

The activities we have described — the customer service focus and cost control efforts of our core business, and the performance of our market-driven enterprises — will help position DQE to continue to be an industry leader into the 21st century. Already a low variable-cost producer of electricity, we will continue to search out new energy-related products and services for today's customers and tomorrow's new customer base. Through it all, we will continue to cultivate the entrepreneurial spirit of the men and women of DQE as we work together through continuing change in our industry toward our ultimate goal of providing exceptional shareholder value.

Condensed Financial Statements

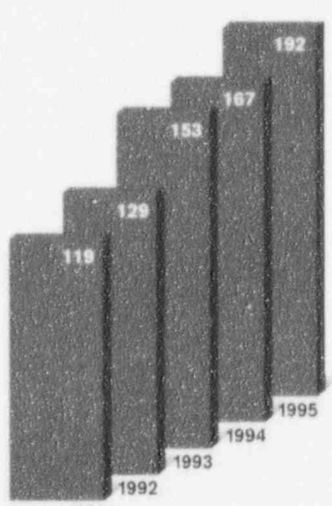
Condensed Statement of Consolidated Income

(Millions of Dollars, Except Per Share Amounts)

		Year Ended December 31, 1995	1994
WARM SUMMER IN UTILITY SERVICE TERRITORY	Revenues from sales of electricity	$1,139	$1,134
	Fuel and purchased power expenses	232	244
	Net electric revenues	907	890
	Other revenues	81	90
	Net operating revenues	988	980
ACCELERATED RECOVERY OF FIXED COSTS	Operating and maintenance expenses	385	408
	Depreciation and amortization	192	167
	Taxes other than income taxes	89	88
	Non-energy operating expenses	666	663
	Operating income	322	317
CONTINUED GROWTH IN MARKET-DRIVEN OPERATIONS	Equity investment and other income	52	43
	Interest and other charges	107	110
	Income before income taxes	267	250
	Income taxes	96	93
	Net income	$ 171	$ 157
NINTH CONSECUTIVE ANNUAL EARNINGS INCREASE	*Earnings per share*	$ 2.20	$ 1.98

Depreciation & Amortization Expense
(millions of dollars)

Increased capital recovery will lower fixed generation costs and bette. position Duquesne Light for increasing competition.



Condensed Consolidated Balance Sheet

(Millions of Dollars)

CONTINUED GROWTH IN MARKET-DRIVEN OPERATIONS

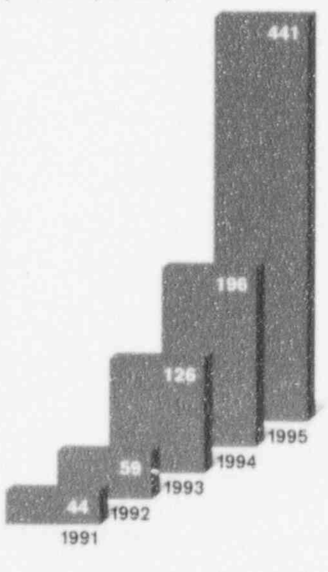
DEPRECIATION EXCEEDS NEW CAPITAL EXPENDITURES

IMPROVING CAPITALIZATION RATIOS

	December 31 1995	1994
Current assets	$ 238	$ 335
Long-term investments	441	196
Property, plant and equipment	3,060	3,140
Regulatory assets	672	711
Other non-current assets	48	45
Total assets	$4,459	$4,427
Current liabilities	$ 286	$ 327
Deferred income	222	64
Non-current liabilities	1,150	1,286
Long-term debt	1,401	1,378
Total liabilities	3,059	3,055
Preferred and preference stock	71	95
Common shareholders' equity	1,329	1,277
Total liabilities and equity	$4,459	$4,427

Future earnings growth will come from the sale of new products and services related to our core business. These energy solutions are being developed and implemented through our market-driven subsidiaries.

Long-Term Investments
(millions of dollars)



CONDENSED STATEMENT OF CONSOLIDATED CASH FLOWS
(MILLIONS OF DOLLARS)

	Year Ended December 31, 1995	1994
Operating cash flows	$379	$375
Changes in working capital	46	(32)
Other	29	26
Cash provided from operating activities	454	369
Long-term investments	(188)	(67)
Capital expenditures	(94)	(121)
Other	(4)	(12)
Cash used by investing activities	(286)	(200)
Common stock dividends	(94)	(89)
Common stock repurchases	(21)	(23)
Net reduction of long-term obligations	(47)	(74)
Change in notes payable	(20)	33
Other	(11)	2
Cash used by financing activities	(193)	(151)
Net change in cash	$(25)	$ 18

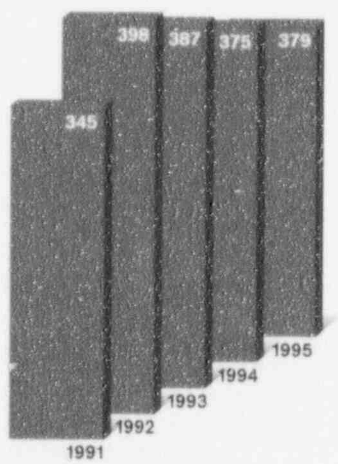
LOWER CAPITAL EXPENDITURES

DIVIDENDS PER SHARE INCREASED

CONTINUED DEBT AND PREFERRED STOCK REDEMPTIONS

Positive cash flow allowed DQE to meet all of its operating and construction requirements, improve its capital structure and develop its market-driven operations.

Net Operating Cash Flow*
(millions of dollars)



*Excludes working capital and other balance sheet changes.

Selected Financial Data

(Millions of Dollars, Except Per Share Amounts)

	1995	1994	1993	1992	1991	1990	1986
Selected Income Statement Items:							
Revenues from sales of electricity	$1,139	$1,134	$1,120	$1,116	$1,139	$1,094	$ 869
Fuel and purchased power expenses	232	244	238	239	254	229	234
Net electric revenues	907	890	882	877	885	865	635
Other revenues	81	90	63	37	38	31	15
Net operating revenues	988	980	945	914	923	896	650
Operating and maintenance expenses	385	408	408	357	365	373	234
Depreciation and amortization	192	167	153	129	119	122	74
Taxes other than income taxes	89	88	71	84	94	80	71
Non-energy operating expenses	666	663	632	570	578	575	379
Operating income	322	317	313	344	345	321	271
Equity investment and other income	52	43	28	42	36	46	(17)
Interest and other charges	107	110	120	132	142	157	148
Income taxes	96	93	80	112	105	88	(4)
Changes in accounting principles	—	—	3	—	—	—	—
Net income	$ 171	$ 157	$ 144	$ 142	$ 134	$ 122	$ 110
Earnings per share	$2.20	$1.98	$1.81	$1.78	$1.67	$1.49	$1.00
Ratio of earnings to fixed charges (pre-tax)	2.73	2.57	2.29	2.24	2.10	1.90	1.75
Selected Balance Sheet Items:							
Long-term investments	$ 441	$ 196	$ 126	$ 59	$ 44	$ 18	$ —
Property, plant and equipment	$3,060	$3,140	$3,168	$3,037	$3,053	$3,048	$3,491
Total assets	$4,459	$4,427	$4,550	$3,778	$3,851	$3,834	$3,997
Total capitalization	$2,801	$2,750	$2,781	$2,716	$2,669	$2,770	$3,085
Capitalization Ratios:							
Common shareholders' equity	47.5%	46.4%	44.2%	43.1%	41.6%	39.0%	39.0%
Preferred and preference stock	2.5%	3.5%	4.8%	4.9%	5.2%	6.8%	8.7%
Long-term debt	50.0%	50.1%	51.0%	52.0%	53.2%	54.2%	52.3%
Selected Common Stock Information:							
Average shares outstanding (millions)	77.7	79.0	79.5	79.4	80.1	81.6	109.4
Shares outstanding at year-end (millions)	77.6	78.5	79.5	79.4	79.4	80.6	109.7
Market capitalization	$2,386	$1,550	$1,829	$1,708	$1,621	$1,337	$896
Dividends declared	$94	$89	$86	$81	$78	$75	$103
Dividends declared per share	$1.21	$1.13	$1.08	$1.03	$ .97	$ .92	$ .94
Dividend payout ratio	54.1%	56.4%	58.8%	56.9%	57.6%	60.7%	107.9%
Dividend yield at year-end	4.2%	5.7%	4.6%	5.0%	5.0%	5.8%	9.8%
Price-earnings ratio at year-end	14.0	9.9	12.7	12.1	12.3	11.1	8.1
Return on average common equity	13.1%	12.5%	12.0%	12.4%	12.2%	11.3%	9.3%

Selected Operating Data

	1995	1994	1993	1992	1991	1990	1986
Sales of Electricity (kilowatt-hours):							
Average annual residential use	6,474	6,170	6,201	5,901	6,331	5,953	5,821
Electric energy sales billed (millions):							
Residential	3,378	3,219	3,231	3,069	3,285	3,078	2,957
Commercial	5,729	5,563	5,490	5,358	5,450	5,236	4,724
Industrial	3,237	3,256	3,046	3,059	3,042	3,296	2,734
Miscellaneous	84	84	84	83	84	84	99
Total sales to customers	12,428	12,122	11,851	11,569	11,861	11,694	10,514
Sales to other utilities	2,975	3,212	2,821	4,060	2,979	1,830	2,091
Total sales	15,403	15,334	14,672	15,629	14,840	13,524	12,605
Percentage Change in Energy Sales:							
Residential	4.9	(0.4)	5.3	(6.6)	6.7	(1.3)	3.8
Commercial	3.0	1.3	2.5	(1.7)	4.1	1.8	4.1
Industrial	(0.6)	6.9	(0.4)	0.6	(7.7)	2.3	(22.4)
Miscellaneous	0.0	0.0	1.2	(1.2)	0.0	0.0	(2.0)
Total sales to customers	2.5	2.3	2.4	(2.5)	1.4	1.1	(4.5)
Sales to other utilities	(7.4)	13.9	(30.5)	36.3	62.8	(12.9)	7.8
Total Sales	0.4	4.5	(6.1)	5.3	9.7	(1.1)	(2.6)
Energy Supply and Production Data:							
Energy supply (millions of kilowatt-hours):							
Net generation - system plants	14,201	14,678	14,056	15,074	14,220	13,266	12,456
Purchased and net interchanged power	1,202	656	616	555	620	258	149
Total energy supply	15,403	15,334	14,672	15,629	14,840	13,524	12,605
Generating capability (megawatts)	2,834	2,834	2,834	2,834	2,835	2,835	2,908
Peak demand (megawatts)	2,666	2,535	2,499	2,308	2,402	2,379	2,132
Cost of fuel per million BTU	131.37¢	137.23¢	143.65¢	140.15¢	153.70¢	149.62¢	165.34¢
Average cost of generation per kilowatt-hour	2.22¢	2.23¢	2.33¢	2.19¢	2.44¢	2.51¢	2.55¢
Customer Data:							
Telephone access:							
% of customers waiting fewer than 30 seconds	87%	86%	76%	41%	26%	—	—
Service interruptions:							
Average System Availability Index	99.99%	99.99%	99.99%	99.99%	99.99%	99.99%	99.98%
Number of customers at year-end (thousands)							
Residential	522.9	522.6	522.3	521.2	520.0	518.3	509.1
Commercial	53.8	53.6	52.9	52.8	52.6	52.3	50.3
Industrial	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Other	1.9	1.9	1.9	1.8	1.9	1.9	1.8
Total customers	580.6	580.1	579.1	577.8	576.5	574.5	563.2
Market-Driven Operations:							
Office rental property occupancy rate	91%	91%	75%	—	—	—	—
Airport service availability	100%	99.99%	99.97%	—	—	—	—
Annual long-term investment activity (millions)	$188	$67	$72	$22	$7	—	—

Board of Directors

(All Terms 3 Years)

Daniel Berg

66. Term expires 1997 (1, 6). Institute Professor, Rensselaer Polytechnic Institute. Directorships include Hy-Tech Machine, Inc. (specialty parts), Joachim Machinery Co., Inc. (distributor of machine tools), and Chester Engineers.

Doreen E. Boyce

61. Term expires 1998 (2, 5). President of the Buhl Foundation (supports educational and community programs). Directorships include Microbac Laboratories, Inc. and Dollar Bank, Federal Savings Bank. Trustee of Franklin & Marshall College.

Robert P. Bozzone

62. Term expires 1997 (1, 2). Vice Chairman of Allegheny Ludlum Corporation (specialty metals production). Directorships include Allegheny Ludlum Corporation; Chairman, Pittsburgh branch of the Federal Reserve Bank of Cleveland. Trustee of Rensselaer Polytechnic Institute.

Sigo Falk

61. Term expires 1996 (2, 3, 4). Management of personal investments. Chairman of Maurice Falk Medical Fund and Chatham College Board of Trustees. Directorships include the Historical Society of Western Pennsylvania and the Allegheny Land Trust.

William H. Knoell

71. Term expires 1997 (3, 4, 6). Retired Chairman and Chief Executive Officer of Cyclops Industries, Inc. (basic and specialty steels and fabricated steel products; industrial and commercial construction). Directorships include Cabot Oil and Gas Corporation. Life trustee of Carnegie Mellon University.

David D. Marshall

43. Term expires 1998 (5, 6). Executive Vice President of DQE; President and Chief Operating Officer of Duquesne Light. Directorships include Southwestern Pennsylvania Industrial Resource Center (economic development). Trustee, Vice President and Secretary of Penn's Southwest Association (economic development).

Robert Mehrabian

54. Term expires 1998 (1, 5, 6). President, Carnegie Mellon University; Dean, College of Engineering, University of California at Santa Barbara, 1983-90. Directorships include PPG Industries, Inc. (producer of glass, chemicals, coatings and resins), and Mellon Bank Corporation.

Thomas J. Murrin

66. Term expires 1997 (3, 6). Dean, A.J. Palumbo School of Business Administration, Duquesne University; former Deputy Secretary of U.S. Dept. of Commerce; former President, Westinghouse Electric Corporation Energy and Advanced Technology Group. Directorships include Motorola, Inc. Member of the Executive Committee of the U.S. Council on Competitiveness and Chairman of the District Export Council.

Robert B. Pease

70. Term expires 1996 (1, 5). Senior Vice President, National Development Corporation (real estate); Executive Director, Allegheny Conference on Community Development, 1968-91. Directorships include Regional Industrial Development Corporation of Southwestern Pennsylvania.

Eric W. Springer

66. Term expires 1996 (1, 4). Partner of Horty, Springer and Mattern, P.C. (attorneys-at-law). Directorships include Presbyterian University Hospital. Past president of the Allegheny County Bar Association.

Wesley W. von Schack

51. Term expires 1996 (3, 4, 6). Chairman, President and Chief Executive Officer of DQE; Chairman and Chief Executive Officer of Duquesne Light. Directorships include Mellon Bank Corporation, RMI Titanium Co., the Pittsburgh branch of the Federal Reserve Bank of Cleveland; Chairman, the Regional Industrial Development Corporation of Southwestern Pennsylvania, and the Pittsburgh Cultural Trust. Also a life trustee of Carnegie Mellon University.

DQE/Duquesne Light Committees:
1. Audit
2. Compensation
3. Finance
4. Nominating

Duquesne Light Committees:
5. Employment and Community Relations
6. Nuclear Review

1995 Financial Information

CONTENTS

COMPANY REPORT ON FINANCIAL STATEMENTS

The Company is responsible for the financial information and representations contained in the financial statements and other sections of this annual report to shareholders. The Company believes that the consolidated financial statements have been prepared in conformity with generally accepted accounting principles that are appropriate in the circumstances to reflect, in all material respects, the substance of events and transactions that should be included in the statements and that the other information in the annual report to shareholders is consistent with those statements. In preparing the financial statements, the Company makes informed judgments and estimates based on currently available information about the effects of certain events and transactions. The Company maintains a system of internal accounting control designed to provide reasonable assurance that the Company's assets are safeguarded and that transactions are executed and recorded in accordance with established procedures. There are limits inherent in any system of internal control and such limits are based on recognition that the cost of such a system should not exceed the benefits derived. The system of internal accounting control is supported by written policies and guidelines and is supplemented by a staff of internal auditors. The Company believes that the internal accounting control system provides reasonable assurance that its assets are safeguarded and the financial information is reliable.

Wesley W. von Schack

Wesley W. von Schack
Chairman of the Board, President
and Chief Executive Officer

Gary L. Schwass

Gary L. Schwass
Executive Vice President,
Chief Financial Officer and Treasurer

Following are explanations of certain financial and operating terms used in our report and unique in the utility business.

Allowance for Funds Used During Construction (AFC)

AFC is an amount recorded on the books of a utility during the period of construction of utility assets. The amount represents the estimated cost of both debt and equity used to finance the construction.

Baseload

The amount of electric power delivered or needed at the lowest point of demand during the day.

Construction Work In Progress (CWIP)

This amount represents assets in the process of construction but not yet placed in service. The amount is shown on the consolidated balance sheet as a component of property, plant and equipment.

Deferred Energy Costs

In conjunction with the Energy Cost Rate Adjustment Clause, the Company records deferred energy costs to offset differences between actual energy costs and the level of energy costs currently recovered from electric utility customers.

Demand

The amount of electricity delivered to consumers at any instant or averaged over a period of time.

Energy Cost Rate Adjustment Clause (ECR)

The Company recovers through the ECR, to the extent that such amounts are not included in base rates, the cost of nuclear fuel, fossil fuel and purchased power costs and passes to its customers the profits from short-term power sales to other utilities.

Federal Energy Regulatory Commission (FERC)

The FERC is an independent five-member commission within the United States Department of Energy. Among its many responsibilities, the FERC sets rates and charges for the wholesale transportation and sale of natural gas and electricity, and licenses hydroelectric power projects.

Interruptible Customer

An interruptible customer receives a discount in exchange for allowing temporary interruptions in his service during the Company's peak load periods or during emergency conditions.

Kilowatt (KW)

A kilowatt is a unit of power or capacity. A kilowatt hour (KWH) is a unit of energy or kilowatts times the length of time the kilowatts are used. For example, a 100-watt bulb has a demand of .1 KW and, if burned continuously, will consume 1 KWH in ten hours. One thousand KWs is a megawatt (MW). One thousand KWHs is a megawatt hour (MWH).

Nuclear Decommissioning Costs

Decommissioning costs are expenses to be incurred in connection with the entombment, decontamination, dismantlement, removal and disposal of the structures, systems and components of a nuclear power plant that has permanently ceased the production of electric energy.

Peak Demand

Peak demand is the amount of electricity required during periods of highest usage. Peak periods fluctuate by season and generally occur in the morning hours in winter and in late afternoon during the summer.

Pennsylvania Public Utility Commission (PUC)

The Pennsylvania governmental body that regulates all utilities (electric, gas, telephone, water, etc.), which is made up of five members nominated by the governor and confirmed by the senate.

Regulatory Asset

Costs that the Company would otherwise have charged to expense which are capitalized or deferred because these costs are currently being recovered or because it is probable that the PUC and the FERC will allow recovery of these costs through the ratemaking process.

Retail or Wholesale Access

The ability of customers to contract for electrical energy from competing generating suppliers.

Stranded Cost

Stranded costs include any prudent utility investment, commitments or expenses not yet recovered, made during a period when there was an obligation or authorization to provide service at a regulated price, that are no longer necessary or economical due to a change in statute or regulatory policy which allows others to compete for the utility's customers. For example, the Company recently refinanced its long-term debt. Refinancing costs will be recovered and amortized for accounting purposes over the term of the debt, unless regulatory changes prevent future recovery, and result in "stranded costs."

Wheeling

An electric operation wherein transmission facilities of one system are used to transmit power of another system.

DQE 1995 Financial Information

Corporate Structure

DQE is an energy services holding company formed in 1989. Its subsidiaries are Duquesne Light Company (Duquesne), Duquesne Enterprises (DE), DQE Energy Services (DES) and Montauk. DQE and its subsidiaries are collectively referred to as the Company.

Duquesne is an electric utility engaged in the production, transmission, distribution and sale of electric energy, and the largest of DQE's subsidiaries. DE makes strategic investments related to DQE's core energy business. These investments enhance DQE's capabilities as an energy provider, increase asset utilization, and act as a hedge against changing business conditions. DES was formed in August 1995 and is a marketing and development company providing energy solutions for customers in domestic and international markets. Montauk is a financial services company that makes long-term investments and provides financing for the Company's initiatives in high quality products, services and energy solutions for its customers.

The Company's Electric Service Territory

The Company's utility operations provide electric service to customers in Allegheny County, including the City of Pittsburgh, and Beaver County. This represents a service territory of approximately 800 square miles in southwestern Pennsylvania. The population of the area served by the Company's electric utility operations, based on 1990 census data, is approximately 1,510,000, of whom 370,000 reside in the City of Pittsburgh. In addition to serving approximately 580,000 customers within this service area, the Company's utility operations also sell electricity to other utilities beyond the Company's service territory.

Regulation

The Company's electric utility operations are subject to regulation by the Pennsylvania Public Utility Commission (PUC), as well as to regulation by the Federal Energy Regulatory Commission (FERC) under the *Federal Power Act* with respect to rates for interstate sales, transmission of electric power, accounting and other matters.

The Company's electric utility operations are also subject to regulation by the Nuclear Regulatory Commission (NRC) under the *Atomic Energy Act of 1954*, as amended, with respect to the operation of its jointly owned/leased nuclear power plants, Beaver Valley Unit 1 (BV Unit 1), Beaver Valley Unit 2 (BV Unit 2) and Perry Unit 1. The Company is also subject to the accounting and reporting requirements of the United States Securities and Exchange Commission.

The Company's consolidated financial statements report regulatory assets and liabilities in accordance with *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71)*, and reflect the effects of the ratemaking process. In accordance with *SFAS No. 71*, the Company's consolidated financial statements reflect regulatory assets and liabilities based on current cost-based ratemaking regulations. The regulatory assets represent probable future revenue to the Company because provisions for these costs are currently included, or are expected to be included, in charges to electric utility customers through the ratemaking process.

The Company's electric utility operations currently satisfy the *SFAS No. 71* criteria. However, a company's utility operations or a portion of such operations could cease to meet these criteria for various reasons, including a change in the PUC or the FERC regulations. Should the Company's electric utility operations cease to meet the *SFAS No. 71* criteria, the Company would be required to write off any regulatory assets or liabilities for those operations that no longer meet these requirements. Management will continue to evaluate significant changes in the regulatory and competitive environment in order to assess the Company's overall consistency with the criteria of *SFAS No. 71*.

Results of Operations

Seasonality

Sales of electricity to customers by the Company's electric utility operations tend to increase during the warmer summer and colder winter seasons because of greater customer use of electricity for cooling and heating.

In the near term, weather conditions and the overall level of business activity in the Company's electric utility service territory are expected to continue to be the primary factors affecting sales of electricity to customers. In the long-term, the Company's electric sales may also be affected by increased competition in the electric utility industry. (See "Competition" discussion on page 35.)

Sales of Electricity to Customers

Operating revenues are derived from the Company's sales of electricity to customers and are based on rates authorized by the PUC. These rates are cost-based and are designed to recover the Company's energy and other operating expenses and investment in electric utility assets and to provide a return on the investment. Sales to the Company's 20 largest customers accounted for 14.2 percent and 14.6 percent of customer revenues in 1995 and 1994, respectively. Sales to USX Corporation, the Company's largest customer, accounted for 3.7 percent and 3.8 percent of total

1995 and 1994 customer revenues, respectively. Total kilowatt-hour (KWH) sales to customers in 1995 increased 2.5 percent when compared to KWH sales to customers in 1994. In response to extreme 1995 summer and winter temperatures, residential and commercial KWH sales increased 4.9 percent and 3.0 percent, respectively. Industrial sales volume in 1995 declined when compared to the prior year because of temporary production facility outages experienced by some of the Company's large industrial customers. The severe weather conditions in 1995 also resulted in higher residential KWH sales volume when compared to 1993.

Components of Change in Operating Revenues from the Prior Year

	1995	1994
	(Amounts in Millions of Dollars)	
Revenues from Sales of Electricity:		
Net customer revenues	$ 7.8	$ 6.2
Utilities	(2.3)	7.6
Revenues from total sales of electricity	5.5	13.8
Other operating revenues	(9.2)	26.9
Total Operating Revenues	$(3.7)	$40.7

Customer revenues fluctuate as a result of changes in sales volume and changes in fuel and other energy costs.

Net customer revenues in 1995 when compared to 1994 increased by $7.8 million, or 0.7 percent. The change is the net result of higher sales, partially offset by lower energy costs per megawatt hour (MWH), the benefits of which are passed through to the customers in the form of lower rates. The significantly hotter summer temperatures in 1995 resulted in increased sales of electricity to residential customers in particular. Revenues attributable to electric sales to residential customers in 1995 exceeded 1994 residential revenues by $13.2 million, or 3.3 percent. *Net customer revenues* also increased $6.2 million, or 0.6 percent, in 1994 when compared to 1993. The 1994 variation represented higher sales to commercial and industrial customers, driven in part by an expanded customer base.

Net customer revenues for 1994 and 1993 include *phase-in deferrals* that represented the deferral and subsequent recovery of revenues resulting from a $232 million rate increase granted in early 1988. The PUC required the Company to phase this increase in during a six-year period, which ended in April 1994. During this phase-in period, the rate increase was recognized in *operating revenues*. (See "1987 Rate Case" discussion in Note F to the consolidated financial statements on page 48.)

Sales to Other Utilities

Short-term sales to other utilities are regulated by the FERC and are made at market rates. Short-term power sales to other utilities in 1995, 1994 and 1993 were 2,974,797 KWH, 3,212,110 KWH and 2,820,920 KWH, respectively. Fluctuations in electricity sales to other utilities are related to the Company's customer energy requirements, the energy market and transmission conditions and the availability of the Company's generating stations. Revenues from sales to other utilities were $56.0 million, $58.3 million and $50.7 million in 1995, 1994 and 1993, respectively. Sales to other utilities were less prevalent in 1995 than in 1994 because severe weather conditions resulted in greater sales to the Company's electric utility customers. (See "Sales of Electricity to Customers" discussion on page 23.) Increased customer sales reduce power available to sell to other utilities. Future levels of short-term sales to other utilities will be affected by the resolution of the Company's proposed sale of its ownership interest in the Ft. Martin Power Station and by the outcome of the Company's FERC filings requesting firm transmission access. (See "Sale of Ft. Martin" and "Transmission Access" discussions on pages 31 and 36, respectively.)

Generally, the Company is permitted to recover (to the extent that such amounts are not included in base rates) fuel and other energy costs from its customers through an Energy Cost Rate Adjustment Clause (ECR), subject to the PUC review. This revenue adjustment also includes a credit to the Company's customers for profits from short-term sales to other utilities. The credit to the Company's customers for profits from short-term sales to other utilities was $15.5 million in 1995, $16.6 million in 1994 and $12.1 million in 1993. Included in a petition currently before the PUC, the Company proposes a five-year annual $5 million credit to the ECR to compensate the Company's electric utility customers for the lost profits from any reduced short-term power sales caused by the sale of its ownership interest in the Ft. Martin Power Station. (See "Energy Cost Rate Adjustment Clause (ECR)" and "Sale of Ft. Martin" discussions on pages 28 and 31, respectively.)

1995 and 1994 customer revenues, respectively. Total kilowatt-hour (KWH) sales to customers in 1995 increased 2.5 percent when compared to KWH sales to customers in 1994. In response to extreme 1995 summer and winter temperatures, residential and commercial KWH sales increased 4.9 percent and 3.0 percent, respectively. Industrial sales volume in 1995 declined when compared to the prior year because of temporary production facility outages experienced by some of the Company's large industrial customers. The severe weather conditions in 1995 also resulted in higher residential KWH sales volume when compared to 1993.

Components of Change in Operating Revenues from the Prior Year

	1995	1994
	(Amounts in Millions of Dollars)	
Revenues from Sales of Electricity:		
Net customer revenues	$ 7.8	$ 6.2
Utilities	(2.3)	7.6
Revenues from total sales of electricity	5.5	13.8
Other operating revenues	(9.2)	26.9
Total Operating Revenues	$(3.7)	$40.7

Customer revenues fluctuate as a result of changes in sales volume and changes in fuel and other energy costs.

Net customer revenues in 1995 when compared to 1994 increased by $7.8 million, or 0.7 percent. The change is the net result of higher sales, partially offset by lower energy costs per megawatt hour (MWH), the benefits of which are passed through to the customers in the form of lower rates. The significantly hotter summer temperatures in 1995 resulted in increased sales of electricity to residential customers in particular. Revenues attributable to electric sales to residential customers in 1995 exceeded 1994 residential revenues by $13.2 million, or 3.3 percent. *Net customer revenues* also increased $6.2 million, or 0.6 percent, in 1994 when compared to 1993. The 1994 variation represented higher sales to commercial and industrial customers, driven in part by an expanded customer base.

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Other Operating Revenues

The Company's non-KWH revenues comprise *other* operating revenues in the Company's statement of consolidated income. *Other* operating revenues decreased $9.2 million in 1995, when compared to the prior year. This decrease largely reflects the restructuring of Chester Engineers (Chester) (formerly, Chester Environmental, Inc.), a wholly owned subsidiary of DE. Conversely, *other* operating revenues expanded in 1994 and 1993 when compared to each of the prior years primarily due to growth in environmental service revenues. This growth included the original acquisition of a 70 percent controlling interest in Chester in August 1993. Chester's revenues have been reflected in *other* operating revenues since that date.

Operating Expenses

Total operating expenses decreased $9.3 million for 1995 when compared to 1994. *Total operating expenses* increased from 1993 to 1994 by $36.9 million. *Fuel and purchased power* expense fluctuations generally result from changes in the cost of fuel, the mix between coal and nuclear generation, the total KWHs sold and generating station availability. Because of the ECR, changes in fuel and purchased power costs normally do not impact earnings.

Components of Change in Fuel and Purchased Power Expense from the Prior Year

	1995	1994
	(Amounts in Millions of Dollars)	
Average unit cost of fuel	**$ (2.3)**	$(3.4)
Generation mix	**(5.2)**	(5.5)
Generation volume	**(6.4)**	7.6
Purchased power	**1.7**	7.7
Total Energy Expense	**$(12.2)**	$ 6.4

The average unit cost of fuel is based on fuel costs divided by generation. The average unit cost of fuel decreased in 1995 when compared to 1994 and 1993 largely because of lower nuclear fuel costs.

Generation mix impacts fuel expense as the Company's nuclear fuel cost per KWH is less than its fossil fuel cost per KWH. During 1993, compared to 1994 and 1995, the Company had more nuclear power station outages, resulting in less nuclear generation and more fossil fuel and purchased power expense.

Generation volume during 1995 decreased 2.7 percent when compared to 1994 due to more generating station outages. Overall nuclear generation increased in 1995 due to strong performances at the nuclear units. (See "Beaver Valley Power Station (BVPS)" and "Perry Unit 1" discussions on page 30.) Major outages at coal stations, including an extended forced outage at the Ft. Martin Power Station, resulted in reduced coal generation which more than offset the increased nuclear generation. During 1994, generation increased 3.4 percent from 1993 due to fewer generating station outages.

Purchased power volume increased in 1995 when compared to 1994 primarily due to generating station outages during periods of extreme weather conditions. Purchased power volume increased in 1994 when compared to 1993 primarily due to the performance of Perry Unit 1.

In 1995, *other operating* expense decreased $25.3 million when compared to 1994. This 1995 reduction reflects, in large part, the restructuring of Chester. In addition, $7.7 million, or 30 percent of this favorable variance, constitutes cost savings attributable to the Company's electric utility operations. *Other operating* expense increased slightly in 1994 compared to 1993 despite a $25.0 million increase in operating expenses at Chester, the result of a full year of ownership in 1994. This increase was offset by similar electric utility cost reductions and by the 1993 recording of a $15.2 million long-term power sale write-off and a $12.8 million property subleasing charge.

Maintenance expense fluctuations primarily result from the timing of scheduled generating station outages, the timing of scheduled transmission and distribution line maintenance and the effect of storms on overhead lines and transformers. Incremental maintenance expense incurred for scheduled refueling outages at the Company's nuclear units is deferred for amortization over the period between refueling outages (generally 18 months). Influenced by extreme weather conditions and the timing of outages at both fossil and nuclear stations, *maintenance* costs incurred by the Company in 1995 exceeded the prior year by $2.0 million. During 1994 and 1993, amortization of deferred nuclear refueling outage expense increased, reflecting the higher costs of refueling outages. Offsetting this increase in 1994 was a decrease in transmission and distribution line maintenance expense.

The Company changed, as of January 1, 1993, its method of accounting for maintenance costs during scheduled major fossil generating station outages. Under the new accounting policy, the Company accrues, over the periods between outages, anticipated expenses for scheduled major fossil generating station outages.

The cumulative effect (approximately $5.4 million, net of income taxes of approximately $3.9 million) of the change on prior years was included in *net income* in 1993. The effect of the change in 1993 was to reduce *income, before the cumulative effect of changes in accounting principles,* by approximately $2.4 million, or $.03 per share, and to reduce *net income*, after the cumulative effect of changes in accounting principles, by approximately $7.8 million, or $.10 per share, based on post-split shares.

Depreciation and amortization expense increased $25.7 million in 1995, primarily due to the change in the Company's electric utility operations composite depreciation rate from 3.0 percent to 3.5 percent effective January 1, 1995. *Depreciation and amortization* expense increased $13.9 million in 1994 when compared to the prior year due to increases in depreciable property and nuclear decommissioning expense.

As part of the Company's plan to optimize generation capacity, a petition pending before the PUC proposes an annual increase in *depreciation and amortization* expense related to the Company's nuclear power investment of $25 million for three years. Consistent with the 1995 increase in the composite depreciation rate, the Company is not seeking a rate increase to recover these additional costs. (See "Sale of Ft. Martin" discussion on page 31.)

Taxes other than income taxes were lower in 1993 compared to 1995 and 1994, primarily as a result of a favorable resolution of certain property tax assessments. In 1993, the Company recorded, on the basis of these revised assessments, the expected refunds for overpayments in prior years.

Other Income

Other income increased $9.4 million in 1995 when compared to 1994 primarily due to additional investing activity, including the merger of International Power Machines Corporation (IPM) and Exide Electronics Group, Inc. (Exide). (See "Investing" discussion below.) *Other income* increased $15.0 million in 1994 when compared to 1993 as a result of additional leasing activities in 1994 and a full year's income from investments made during 1993.

Income Taxes

Income taxes were lower in 1993, when compared to 1995 and 1994, because of a favorable settlement with the Internal Revenue Service (related to the Company's 1988 federal income tax return and the Company's 1989 consolidated federal income tax return). The remaining fluctuations result from changes in taxable income. During 1994 the statutory Pennsylvania income tax rate was reduced from 12.25 percent to 9.99 percent. This resulted in a net decrease of $80.5 million in deferred tax liabilities and a corresponding reduction in the regulatory receivable.

Capital Expenditures

The Company spent approximately $78.7 million in 1995, $94.3 million in 1994 and $100.6 million in 1993 for electric utility construction. These amounts were expended to improve and/or expand electric utility production, transmission and distribution systems. The Company's capital expenditures for electric utility construction focus on extending service to new customers, providing for the replacement of utility property and modifying facilities consistent with the most current environmental and safety regulations. The Company estimates that it will spend, excluding allowance for funds used during construction (AFC) and nuclear fuel, approximately $90 million, $90 million and $100 million for electric utility construction during 1996, 1997 and 1998, respectively. Approximately $5 million of capital expenditures for reliability enhancements to the simple cycle units located at Brunot Island (BI) contemplated in the Company's petition before the PUC are excluded from these estimates. (See "Sale of Ft. Martin" discussion on page 31.) The Company expects that funds generated from operations will continue to be sufficient to finance a large part of its capital needs. The Company's market-driven capital expenditures were for real estate investments at DE. These real estate investments were $16.7 million and $26.8 million in 1995 and 1994, respectively.

Investing

The Company's long-term investments focus in five principal areas: affordable housing, natural gas reserves limited partnerships, lease and leasehold investments, environmental services, and energy solution investments. Investing activities increased in 1995, after staying relatively constant in 1994 when compared to 1993. The Company invested $41.4 million and $22.1 million in affordable housing funds and $38.7 million and $44.6 million in other leases and investments in 1995 and 1994, respectively. In addition, the Company invested $72.2 million in natural gas reserves limited partnerships and $35.4 million in leveraged leases in 1995.

On February 8, 1995, IPM was acquired by Exide. As a result of this merger, the Company acquired 526,250 shares of Exide common stock, a 6.8 percent interest. Since the merger, the Company has acquired an additional 532,500 shares of Exide for $9.8 million. At December 31, 1995, the Company held an 11.6 percent interest in Exide. *Other long-term investments* at December 31, 1995, included a $15.6 million investment in Exide common stock. *Other long-term investments* at December 31, 1994, included a $2.8 million investment in IPM convertible preferred stock.

On August 31, 1995, Chester repurchased 30 percent of its own outstanding common stock for $6 million. As a result of this purchase, DE owns 100 percent of the outstanding common stock of Chester. Effective February 1, 1996, Chester formally changed its name to Chester Engineers.

Liquidity and Capital Resources

Financing

The Company expects to meet its current obligations and debt maturities through the year 2000 with funds generated from operations and through new financings. At December 31, 1995, the Company was in compliance with all of its debt covenants.

The Company's 1947 first mortgage bond indenture was retired in the third quarter of 1995 following the maturity of the last bond series issued under the indenture. All of the Company's First Collateral Trust Bonds have been issued under a new mortgage indenture that was established in April 1992 (the 1992 Indenture). All First Collateral Trust Bonds became first mortgage bonds when the 1947 mortgage indenture was retired. The 1992 Indenture includes more flexible provisions and eliminates conventions such as mandatory sinking funds and formula-derived maintenance and replacement clauses.

On September 1, 1995, the Company redeemed all of its outstanding shares of $7.20 Preferred Stock for $29.9 million. On August 29, 1995, the Company repurchased $7 million of its 8⅜% First Collateral Trust Bonds maturing in 2024.

In the fourth quarter of 1995, the Company placed $65 million of five-year notes maturing in 2000 bearing an average annual fixed interest rate of 6.49 percent. Interest is payable semi-annually.

In May 1996, $50.0 million of First Collateral Trust Bonds will mature. The Company expects to retire these bonds with internally generated funds or to refinance the bonds.

Short-Term Borrowings

At December 31, 1995, the Company had two extendible revolving credit agreements, including a $100 million facility expiring in August 1996 and a $150 million facility expiring in October 1996. Interest rates on these credit agreements vary. Commitment fees are based on the unborrowed amount of the commitments. Both credit facilities contain two-year repayment periods for any amounts outstanding at the expiration of the revolving credit periods. At December 31, 1995 and 1994, short-term borrowings were $35 million and $60 million, respectively. The weighted average interest rates applied to such borrowings were 6.5 percent and 6.7 percent at December 31, 1995 and 1994, respectively.

Interest and Other Charges

The Company achieved a $2.4 million reduction in *interest and other charges* in 1995, primarily due to the retirement of long-term debt and preferred stock of subsidiaries. The Company's interest on long-term debt and dividends on preferred and preference stock declined to $101.3 million in 1995 from $107.0 million in 1994 and $117.4 million in 1993. Interest expense in 1996 will be influenced by fluctuations in short-term rates and any new financing.

Sale of Accounts Receivable

The Company and an unaffiliated corporation have an agreement that entitles the Company to sell, and the corporation to purchase, on an ongoing basis, up to $50 million of accounts receivable. At December 31, 1995, the Company had sold $7 million of receivables to the unaffiliated corporation. The Company had no receivables sold at December 31, 1994. The accounts receivable sales agreement, which expires in June 1996, is one of many sources of funds available to the Company. The Company may attempt to extend the agreement, or to replace the facility with a similar one or to eliminate it upon expiration.

Nuclear Fuel Leasing

The Company finances its acquisitions of nuclear fuel through a leasing arrangement under which it may finance up to $75 million of nuclear fuel. As of December 31, 1995, the amount of nuclear fuel financed by the Company under this arrangement totaled approximately $40.8 million. The Company plans to continue leasing nuclear fuel to fulfill its requirements at least through September 1998, the remaining term of the leasing arrangement.

Stock Split and Dividends

On April 19, 1995, the Company's board of directors declared a three-for-two stock split for shareholders of record on May 1, 1995. One additional share of *common stock* was issued for every two shares outstanding as of the record date. The Company paid a quarterly dividend of $.30 per share on the post-split shares on each of July 1 and October 1. The quarterly dividend declared in the fourth quarter of 1995 on the post-split shares was increased from $.30 to $.32 per share payable beginning January 1, 1996.

The following information has been restated to reflect the stock split. The Company has continuously paid dividends on *common stock* since 1953. The Company has increased its annual dividend for each of the last eight years to the current annualized dividend rate of $1.28 per share on the post-split shares. The Company's stock price was $30.75 at the end of 1995. The book value per share of common stock was $17.13 at December 31, 1995, which represents a 5.2 percent increase in book value since December 31, 1994. The annual dividends paid have increased by an average compounded rate of 5.5 percent over the past five years, even though the Company has maintained a lower payout ratio than the electric utility industry in general. The Company expects that funds generated from operations will continue to be sufficient to pay dividends. The Company's need for and the availability of funds will be influenced, among other things, by new investment opportunities, by the economic activity within the Company's utility service territory, by competitive and environmental legislation and by regulatory matters experienced by the electric utility industry generally.

Dividends may be paid on the Company's *common stock* to the extent permitted by law and as declared by the board of directors. However, payments of dividends on Duquesne's common stock may be restricted by Duquesne's obligations to holders of preferred and preference stock pursuant to Duquesne's *Restated Articles* of incorporation. No dividends or distributions may be made on Duquesne's common stock if Duquesne has not paid dividends or sinking fund obligations on its preferred or preference stock. Further, the aggregate amount of Duquesne's common stock dividend payments or distributions may not exceed certain percentages of *net income* if the ratio of *total common shareholders' equity* to *total capitalization* is less than specified percentages. As all of Duquesne's common stock is owned by the Company, to the extent that Duquesne cannot pay common dividends, the Company may not be able to pay dividends to its common shareholders. No part of the *retained earnings* of the Company was restricted at December 31, 1995.

Changes in the Number of Shares of DQE Common Stock Outstanding

	1995	1994	1993
	(Amounts in Thousands of Shares)		
Outstanding as of January 1	78,459	79,518	79,425
Reissuance from treasury stock	83	116	93
Repurchase of common stock	(986)	(1,175)	—
Outstanding as of December 31	77,556	78,459	79,518

Electric rates charged by the Company to its customers are regulated by the PUC. Electric rates charged to the Borough of Pitcairn and charged for sales to other electric utilities are regulated by the FERC. These rates are designed to recover the Company's electric utility operating expenses, investment in electric utility assets, and to provide a return on those investments. Sales to other utilities are made at market rates. At this time, the Company has no pending base rate case and has no immediate plans to file a base rate case. In the Company's petition currently before the PUC for the sale of its ownership interest in the Ft. Martin Power Station, the Company proposes to freeze its base rates for a five-year period. (See "Sale of Ft. Martin" discussion on page 31.)

Energy Cost Rate Adjustment Clause (ECR)

Through the ECR, the Company recovers (to the extent that such amounts are not included in base rates) nuclear fuel, fossil fuel and purchased power expenses and, also through the ECR, passes to its customers the profits from short-term power sales to other utilities (collectively, ECR energy costs). Nuclear fuel expense is recorded on the basis of the quantity of electric energy generated and includes such costs as the fee imposed by the United States Department of Energy (DOE) for future disposal and ultimate storage and disposition of spent nuclear fuel. Fossil fuel expense includes the costs of coal, natural gas and fuel oil used in the generation of electricity.

On the Company's statement of consolidated income, these ECR revenues are included as a component of *operating revenues*. For ECR purposes, the Company defers fuel and other energy expenses for recovery, or refunding, in subsequent years. The deferrals reflect the difference

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Rate Matters

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On the Company's statement of consolidated income, these ECR revenues are included as a component of *operating revenues*. For ECR purposes, the Company defers fuel and other energy expenses for recovery, or refunding, in subsequent years. The deferrals reflect the difference

between the amount that the Company is currently collecting from customers and its actual ECR energy costs. The PUC annually reviews the Company's ECR energy costs for the fiscal year April through March, compares them to previously projected ECR energy costs and adjusts the ECR for over- or under-recoveries and for two PUC-established coal cost standards. (See "Deferred Coal Costs" and "Warwick Mine Costs" discussions in Note F to the consolidated financial statements on page 49.)

Over- or under-recoveries from customers are recorded on the consolidated balance sheet as payable to, or receivable from, customers. At December 31, 1995, $5.8 million was payable to customers and shown as *other current liabilities*. At December 31, 1994, $5.9 million was receivable from customers and shown as *other current assets*.

Deferred Rate Synchronization Costs

In 1987, the PUC approved the Company's petition to defer initial operating and other costs of Perry Unit 1 and BV Unit 2. The Company deferred the costs incurred from November 17, 1987, when the units went into commercial operation, until March 25, 1988, when a rate order was issued. In its order, the PUC postponed ruling on whether these costs would be recoverable from the Company's electric utility customers. At December 31, 1995, these costs totaled $51.1 million, net of deferred fuel savings related to the two units. The Company is not earning a return on the deferred costs. The Company believes that these costs are recoverable. In 1990 and 1995, the PUC permitted other Pennsylvania electric utilities rate recovery of such costs.

Property, Plant and Equipment (PP&E)

Investment in PP&E and Accumulated Depreciation

The Company's total investment in *property, plant and equipment* and the related *accumulated depreciation* balances for major classes of property at December 31, 1995 and 1994, are as follows:

PP&E and Related Accumulated Depreciation at December 31

(Amounts in Thousands of Dollars)

	1995			1994		
	Investment	Accumulated Depreciation	Net Investment	Investment	Accumulated Depreciation	Net Investment
Electric Production	$2,501,974	$ 885,389	$ 1,616,585	$2,474,032	$ 796,338	$1,677,694
Electric Transmission	296,953	110,242	186,711	295,512	105,217	190,295
Electric Distribution	1,143,111	347,399	795,712	1,119,247	323,922	795,325
Electric General	314,844	141,133	173,711	305,335	123,766	181,569
Property Held for Future Use	216,633	94,283	122,350	216,206	94,283	121,923
Property Held Under Capital Leases	133,381	74,874	58,507	162,732	91,376	71,356
Other	139,217	32,557	106,660	136,460	35,081	101,379
Total	$4,746,113	$1,685,877	$3,060,236	$4,709,524	$1,569,983	$3,139,541

Joint Interests in Generating Units

The Company has various contracts with The Potomac Edison Company, Monongahela Power Company, Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company (CEI) and The Toledo Edison Company that include provisions for coordinated maintenance responsibilities, limited and qualified mutual back-up in the event of outages and certain capacity and energy transactions.

Under the agreements governing the operation of these jointly owned generating units, the day-to-day operating authority is assigned to a specific company. CEI has such authority for Perry Unit 1 and Eastlake Unit 5; Ohio Edison Company has authority for Sammis Unit 7; Pennsylvania Power Company has authority for Bruce Mansfield Units 1, 2 and 3; and Monongahela Power Company operates Ft. Martin Unit 1.

In September 1995, the Company served a demand for arbitration on CEI seeking, among other things, a partition of Eastlake Unit 5 through a sale of the Company's interest therein and a termination of its operating agreement with CEI for that unit. The demand alleges, among other things, the improper allocation by CEI of fuel and related costs between itself and the Company; the mismanagement by CEI of the closing of the Saginaw Mine, which historically supplied coal to the unit; and the concealment by CEI of information. In October 1995, CEI filed its own arbitration demand and asserted counterclaims seeking the Company's alleged share of costs relating to the unit. A panel of arbitrators has been appointed.

The Company has a joint interest in the following nuclear power stations with the following companies:

	Beaver Valley Unit 1	Beaver Valley Unit 2	Perry Unit 1
Duquesne	* 47.50%	* 13.74% (c)	13.74%
Ohio Edison Company	35.00%	41.88%	30.00%
Pennsylvania Power Company (a)	17.50%	-	5.24%
CEI (b)	-	24.47%	* 31.11%
Toledo Edison Company (b)	-	19.91%	19.91%

*Denotes Operator

(a) Subsidiary of Ohio Edison Company

(b) Subsidiary of Centerior Energy Corporation

(c) In 1987, the Company sold and leased back its 13.74 percent interest in BV Unit 2; the sale was exclusive of transmission and common facilities. The total sales price of $537.9 million was the appraised value of the Company's interest in the property. The Company subsequently leased back its interest in the unit for a term of 29.5 years. The lease provides for semiannual payments and is accounted for as an operating lease. The Company is responsible under the terms of the lease for all costs of its interest in the unit. (See "Property, Plant and Equipment," Note E, to the consolidated financial statements on page 47.)

The Company has a joint interest in the following fossil plants with the following companies:

	Sammis Unit 7	Bruce Mansfield Unit 1	Bruce Mansfield Unit 2	Bruce Mansfield Unit 3	Eastlake Unit 5	Ft. Martin Unit 1
Duquesne	31.20%	29.30%	8.00%	13.74%	31.20%	50.00%
Ohio Edison Company	*48.00%	60.00%	39.30%	35.60%	-	-
Pennsylvania Power Company (a)	20.80%	* 4.20%	* 6.80%	* 6.28%	-	-
CEI (b)	-	6.50%	28.60%	24.47%	* 68.80%	-
Toledo Edison Company (b)	-	-	17.30%	19.91%	-	-
Potomac Edison Company (c)	-	-	-	-	-	25.00%
Monongahela Power Company (c)	-	-	-	-	-	* 25.00%

*Denotes Operator

(a) Subsidiary of Ohio Edison Company

(b) Subsidiary of Centerior Energy Corporation

(c) Subsidiary of, and currently known as, Allegheny Power System

Beaver Valley Power Station (BVPS)

BVPS continues to demonstrate excellence in operating performance. During 1995, BV Unit 1 and BV Unit 2 both underwent scheduled refueling outages, which were completed in the shortest duration in both the units' history. Further exemplifying BVPS' accomplishments, both refueling outages were completed under budgeted cost. In spite of these scheduled refueling outages, the combined capacity factor for the units averaged 80 percent during 1995. Capacity factor is a key production measure and indicates how well the plant operated based on its design capacity. It is the ratio of the power actually generated by a facility to the facility's rated capacity during a given period of time. Also, BV Unit 2 achieved an unplanned capability loss factor of 0.7 percent, which is significantly better than the industry standard of 4.0 percent. This factor measures how much power production was lost due to unplanned outages.

In addition to optimizing generation and cost efficiency, BVPS management continues to emphasize safety in operations. During 1995, BVPS employees achieved the milestone of more than three million hours worked without incurring a single lost time accident.

Perry Unit 1

The Company has a 13.74 percent ownership interest in Perry Unit 1, a nuclear generating unit located in Ohio and operated by CEI.

Perry Unit 1 experienced improved performance during 1995, a year without a refueling outage, and achieved a capacity factor of 87.5 percent.

CEI has submitted to the NRC an action plan, called the Perry Course of Action (PCA). CEI management continues to represent to the Company that the PCA is on schedule and will be an effective program to ensure that Perry Unit 1 is in conformance with applicable industry standards. The PCA is scheduled to be completed by the end of Perry Unit 1's fifth refueling outage, presently scheduled for the spring of 1996. The Company cannot predict the effectiveness of the PCA. The Company will continue to monitor closely this situation.

Sale of Ft. Martin

On November 29, 1995, the Company and AYP Capital, Inc., an unregulated subsidiary of the Allegheny Power System (APS), entered into an agreement for the sale of the Company's 50 percent ownership interest in Unit 1 of the Ft. Martin Power Station, for the sum of $169 million. The agreement is subject to all necessary regulatory approvals. On December 20, 1995, the Company filed a Petition for Declaratory Order with the PUC requesting approval for the sale in conjunction with a six-point plan to be financed in part by the proceeds of the Ft. Martin transaction.

Under the plan, the Company offers to freeze its base rates for a period of five years. If approved, the rate freeze is expected to produce a 14 percent reduction in the real price of electricity based on an average annual inflation rate of 2.7 percent. In addition, the Company proposes to record a one-time reduction of approximately $130 million in the value of the Company's nuclear plant investment. The Company also proposes to use the proceeds from the sale to finance reliability enhancements to the simple cycle units located at BI, to retire debt and to reduce equity. The BI simple cycle units will provide 168 megawatts (MW) of peaking capacity and permit the Company to achieve greater operational flexibility in meeting peak system demands. The plan also proposes an annual increase of $25 million for three years in *depreciation and amortization* expense to the Company's nuclear investment, as well as additional annual contributions to its nuclear plant decommissioning funds of $5 million for five years, without any increase in existing electric rates. Lastly, the Company proposes a five-year annual $5 million credit to the ECR to compensate the Company's electric utility customers for the lost profits from any reduced short-term power sales foregone by the sale of its ownership interest in the Ft. Martin Power Station. (See "Energy Cost Rate Adjustment Clause (ECR)" discussion on page 28.)

The PUC is currently reviewing the Company's petition.

Property Held for Future Use

In 1986, the PUC approved the Company's request to remove the 300 MW Phillips Power Station (Phillips) and 240 MW of BI from service and from rate base. The Company expects to recover its net investment in these plants through future electricity sales. The Company believes its investment in these plants will be necessary in order to meet future business needs outlined in the Company's plans for optimizing generation resources. (See "Generation Resource Optimization" discussion on page 37.) If business opportunities do not develop as expected, the Company will consider the sale of these assets. In the event that market demand, transmission access or rate recovery do not support the utilization or sale of the plants, the Company may have to write off part or all of their costs. At December 31, 1995, the Company's net investment in Phillips and BI held for future use was $77.4 million and $44.9 million, respectively.

Employees

At December 31, 1995, DQE and its subsidiaries had 3,839 employees, including 1,178 employees at the Company-operated BVPS. The International Brotherhood of Electrical Workers (IBEW) union represents 2,086 of the Company's employees. The current collective bargaining agreement with the IBEW expires on September 30, 1998.

Electric Utility Operations

Approximately 69 percent of the electric energy generated by the Company's system during 1995 was produced by its coal-fired generating capacity and approximately 31 percent was produced by its nuclear generating capacity. The Company normally experiences its peak loads in the summer. The 1995 customer system peak of 2,666 MW, the highest system peak in the Company's history, occurred on August 16, 1995.

The Company's fossil plants operated at 76 percent availability in 1995 and 85 percent availability in 1994. The Company's nuclear plants operated at 83 percent availability in 1995 and 75 percent in 1994. The timing and duration of scheduled maintenance and refueling outages, as well as the duration of forced outages, affect the availability of power stations.

The Company determines the need for and timing of generation resource additions based on maintaining an adequate level of resources in reserve above the projected weather normalized annual peak demand. In addition, capacity resources throughout the region can supplement the Company's in-service generation resources, if required, through the Company's substantial transmission import capability, currently in excess of 4,000 MW. The North American Electric Reliability Council, of which the Company is a member, uses "capacity margin" to report generating capability when compared to customer demand. Capacity margin is one of the criteria used by the Company in assessing the need for future resources. The Company's capacity margin in 1995 was 11.7 percent. The capacity portfolio reflected in the Company's capacity margin includes in-service generating capacity, plus 21 MW capacity provided by non-utility generation contracts, plus a portion of the capacity from property held for future use available to meet customer needs during peaking or emergency conditions. The customer peak demand reflected in the Company's capacity margin is based on the actual peak demand experienced during the extraordinarily hot 1995 summer weather conditions, less 97 MW of interruptible load resources available from the Company's interruptible customers, but not actually interrupted during the peak period.

The successful resolution of the Company's proposed sale of its ownership interest in Ft. Martin will reduce in-service capacity by 276 MW. The Company expects to replace Ft. Martin capacity by (1) utilizing the 168 MW oil-fired combustion turbines at the BI combined cycle facility, which is property held for future use, and (2) acquiring seasonal peaking capacity from power marketplace resources, as required. These additional resources ensure that adequate capacity will be available to enable the Company to continue to maintain the expected level of power generation reliability.

Fossil Fuel

The Company believes that sufficient coal for its coal-fired generating units will be available from various sources to satisfy its requirements for the foreseeable future. During 1995, approximately 2.6 million tons of coal were consumed at the Company's two wholly owned coal-fired stations, Cheswick Power Station (Cheswick) and Elrama Power Station (Elrama).

The Company owns Warwick Mine, an underground mine located on the Monongahela River approximately 83 river miles from Pittsburgh. Warwick Mine has been excluded from rate base since 1981. The Company temporarily idled the mine in June 1988 due to excess coal inventories. In 1990, the Company restarted the mine and entered into an agreement under which an unaffiliated company will operate the mine until March 2000 and sell the coal produced. Production began in late 1990. The mine produced 1.1 million tons of coal in 1995. The Warwick Mine coal reserves include both high and low sulfur coal; the sulfur content averages in the mid-range at 1.7 percent to 1.9 percent. More than 60 percent of the coal mined at Warwick Mine currently is used by the Company. The Company receives a royalty on any sales of Warwick coal in the open market. These royalties are credited to the Company's ECR. The Warwick Mine currently supplies less than one-fifth of the coal used in the production of electricity at the plants owned or jointly owned by the Company. The Company estimates that, at December 31, 1995, its economically recoverable coal reserves at Warwick Mine were 9.0 million tons. Costs at Warwick Mine and the Company's investment in the mine are expected to be recovered through the cost of coal in the ECR. Recovery is subject to the system-wide coal cost standard. The Company also has an opportunity to earn a return on its investment in the mine through the cost of coal during the period of the system-wide coal cost standard. At December 31, 1995, the Company's net investment in the mine was $14.9 million. The current estimated liability, including final site reclamation, mine water treatment and certain labor liabilities, for mine closing is $34.1 million, and the Company has recorded a liability on the consolidated balance sheet of approximately $15.9 million toward these costs. (See "Warwick Mine Costs" discussion in Note F to the consolidated financial statements on page 49.)

During 1995, 56 percent of the Company's coal supplies were provided by contracts including Warwick Mine, with the remainder satisfied through purchases on the spot market. The Company had four long-term contracts in effect at December 31, 1995, which, in combination with spot market purchases, are expected to furnish an adequate future coal supply. The Company does not anticipate any difficulty in replacing or renewing these contracts as they expire from 1996 through 2002. At December 31, 1995, the Company's wholly owned and jointly owned generating units had on hand an average coal supply of 45 days.

The PUC has established two market price coal cost standards. One applies only to coal delivered at the Bruce Mansfield Power Station (Bruce Mansfield). The other, the system-wide coal cost standard, applies to coal delivered to the remainder of the Company's system. Both standards are updated monthly to reflect prevailing market prices of similar coal. The PUC has directed the Company to defer recovery of the delivered cost of coal to the extent that such cost exceeds generally prevailing market prices for similar coal, as determined by the PUC. The PUC allows deferred amounts to be recovered from customers when the delivered costs of coal fall below such PUC-determined prevailing market prices.

The system-wide coal cost standard extends through March 2000. The unrecovered cost of Bruce Mansfield coal was $8.4 million and the unrecovered cost of the remainder of the system-wide coal was $4.4 million at December 31, 1995. The Company estimates that all deferred coal costs will be recovered. The Company's average cost per ton of coal consumed, including the cost of delivery, during the past three years at generating units which it operates or in which it has an ownership interest was $38.86, $39.12 and $40.08 in 1995, 1994 and 1993, respectively. The cost of coal, which falls within the market price limitations, is recovered from the Company's customers through the ECR. (See "Rate Matters" discussion on page 28, and also see "Deferred Coal Costs" discussion in Note F to the consolidated financial statements on page 49.)

Nuclear Fuel

The cycle of production and utilization of nuclear fuel consists of (1) mining and milling of uranium ore and processing the ore into uranium concentrates, (2) converting uranium concentrates to uranium hexafluoride, (3) enriching the uranium hexafluoride, (4) fabricating fuel assemblies, (5) utilizing the nuclear fuel in the generating station reactor and (6) storing and disposing of spent fuel.

Adequate supplies of uranium and conversion services are under contract for the Company's requirements for its jointly owned/leased nuclear units through 1996. Enrichment services are supplied under a 1984 United States Enrichment Corporation Utility Services Contract entered into

for a period of 30 years by the Company for joint interests in Perry Unit 1, BV Unit 1 and BV Unit 2. Under the terms and conditions of this contract, the Company is committed to 100 percent of its enrichment needs through 1998 and 70 percent in 1999; the Company has terminated, at zero cost, all of its enrichment services requirements for fiscal years 2000 through 2005 and continues to review the need for further services on an annual basis. Fuel fabrication contracts are in place to supply reload requirements for the next two cycles for BV Unit 1, the next two cycles for BV Unit 2 and the next sixteen cycles for Perry Unit 1. The Company will be required to make arrangements for uranium supply and related services as existing commitments expire.

Each utility company is responsible for financing its proportionate share of the costs of nuclear fuel for each nuclear unit in which it has an ownership or leasehold interest. (See "Nuclear Fuel Leasing" discussion on page 27.) The Company's nuclear fuel costs, which are amortized to reflect fuel consumed, are charged to fuel expense and are recovered through rates. The Company estimates that, over the next three years, the amortization of nuclear fuel consumed will exceed the expenditures for new fuel by approximately $1.7 million. The actual nuclear fuel costs to be financed and amortized during the period 1996 through 1998 will be influenced by such factors as changes in interest rates; lengths of the respective fuel cycles; reload cycle design; and changes in nuclear material costs and services, the prices and availability of which are not known at this time. Such costs may also be influenced by other events not presently foreseen.

The Company's nuclear fuel costs related to BV Unit 1, BV Unit 2 and Perry Unit 1 under the fuel lease arrangement are charged to fuel expense based on the quantity of energy generated. Nuclear fuel costs for these units averaged .750, .903 and .918 cents per KWH, inclusive of charges associated with spent fuel, in 1995, 1994 and 1993, respectively. The Company is recovering from its customers the costs associated with the ultimate disposal of spent fuel.

Nuclear Decommissioning

The PUC ruled that recovery of the decommissioning costs for BV Unit 1 could begin in 1977, and that recovery for BV Unit 2 and Perry Unit 1 could begin in 1988. The Company expects to decommission BV Unit 1, BV Unit 2 and Perry Unit 1 no earlier than the expiration of each plant's operating license, 2016, 2026 and 2025, respectively. BV Unit 1 is expected to be placed in safe storage until the expiration of the BV Unit 2 operating license, at which time the units may be decommissioned together.

Based on site-specific studies finalized in 1992 for BV Unit 2, and in 1994 for BV Unit 1 and Perry Unit 1, the Company's share of the total estimated decommissioning costs, including removal and decontamination costs, currently being used to determine the Company's cost of service, are $122 million for BV Unit 1, $35 million for BV Unit 2 and $67 million for Perry Unit 1.

In conjunction with an August 18, 1994, PUC Accounting Order, the Company has increased the annual contribution to its decommissioning trusts by approximately $2 million to bring the total annual funding to approximately $4 million per year. In collaboration with the Company and several other Pennsylvania utilities, the PUC Office of Special Assistants is evaluating various decommissioning issues, including funding methods. The Company expects that any action relating to any forthcoming PUC report will result in further increases in annual contributions to its decommissioning trusts. Consistent with these anticipated future PUC actions, the Company's petition before the PUC for the sale of its ownership interest in the Ft. Martin Power Station provides for additional annual contributions to its nuclear decommissioning funds of $5 million for five years without any increase in existing electric rates. (See "Sale of Ft. Martin" discussion on page 31.)

The Company records decommissioning costs under the category of *depreciation and amortization* expense and accrues a liability, equal to that amount, for nuclear decommissioning expense. Such nuclear decommissioning funds are deposited in external, segregated trust accounts. The funds are invested in a portfolio of municipal bonds, certificates of deposit and United States government securities having a weighted average duration of four to seven years. Trust fund earnings increase the fund balance and the recorded liability. The market value of the aggregate trust fund balances at December 31, 1995, totaled approximately $28.5 million. On the Company's consolidated balance sheet, the decommissioning trusts have been reflected in *other long-term investments*, and the related liability has been recorded as *other non-current liabilities*.

Nuclear Insurance

All of the companies with an interest in BV Unit 1, BV Unit 2 and Perry Unit 1 maintain nuclear property insurance, which provides coverage for property damage, decommissioning and decontamination liabilities. The Company's share of this program provides for $1.2 billion of insurance coverage for its net investment of $407.8 million in the BVPS and $565.5 million in Perry Unit 1, plus its interest in BV Unit 2 with lease commitments of $405.2 million, at December 31, 1995. The lease commitments of $405.2 million represent the net present value of future lease payments discounted at 10.94 percent, the return currently authorized the Company's electric utility operations by the PUC. The Company would be responsible for its share of any damages in excess of insurance coverage. In addition, if the property damage reserves of Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company, are inadequate to cover claims arising from an incident at any United States nuclear site covered by that insurer, the Company could be assessed retrospective premiums totaling a maximum of $10.9 million.

The *Price-Anderson Amendments* to the *Atomic Energy Act of 1954* limit public liability from a single incident at a nuclear plant to $8.9 billion. The Company has purchased $200 million of insurance, the maximum amount available, which provides the first level of financial protection.

Additional protection of $8.3 billion would be provided by an assessment of up to $75.5 million per incident on each nuclear unit in the United States. The Company's maximum total assessment, $56.6 million, which is based on its ownership or leasehold interests in three nuclear generating units, would be limited to a maximum of $7.5 million per incident per year. A further surcharge of 5 percent could be levied if the total amount of public claims exceeded the funds provided under the assessment program. Additionally, a state premium tax (typically 3 percent) could be charged on the assessment and surcharge. Finally, the United States Congress could impose other revenue-raising measures on the nuclear industry if funds prove insufficient to pay claims.

The Company carries extra expense insurance which would pay the incremental cost of any replacement power purchased (in addition to costs that would have been incurred had the units been operating) and other incidental expense after the occurrence of certain types of accidents at its nuclear units in a limited amount for a limited period of time. The coverage provides for 100 percent of the estimated extra expense per week during the 52-week period starting 21 weeks after an accident and 80 percent of such estimate per week for the following 104 weeks, with no coverage thereafter. The amount and duration of actual extra expense could substantially exceed insurance coverage. NEIL also provides this insurance. If NEIL's reserves are inadequate to cover claims at any United States nuclear site covered by that insurer, the Company could be assessed retrospective premiums totaling a maximum of $3.5 million.

Spent Nuclear Fuel Disposal

The *Nuclear Waste Policy Act of 1982* established a policy for handling and disposing of spent nuclear fuel and a policy requiring the established final repository to accept spent fuel. Electric utility companies have entered into contracts with the DOE for the permanent disposal of spent nuclear fuel and high-level radioactive waste in compliance with this legislation. The DOE has indicated that its repository under these contracts will not be available for acceptance of spent fuel before 2010 at the earliest. Existing on-site spent fuel storage capacities at BV Unit 1, BV Unit 2 and Perry Unit 1 are expected to be sufficient until 2016, 2010 and 2011, respectively.

Uranium Enrichment Decontamination and Decommissioning Fund

Nuclear reactor licensees in the United States are assessed annually for the decontamination and decommissioning of DOE enrichment facilities. Assessments are based on the amount of uranium a utility had processed for enrichment prior to enactment of the *National Energy Policy Act of 1992* (NEPA) and are to be paid by such utilities over a 15-year period. At December 31, 1995, the Company's liability for contributions is approximately $9.9 million (subject to an inflation adjustment). Contributions, when made, are recovered from electric utility customers through the ECR.

Environmental Matters

The *Comprehensive Environmental Response, Compensation and Liability Act of 1980* and the *Superfund Amendments and Reauthorization Act of 1986* (Superfund) established a variety of informational and environmental action programs. The United States Environmental Protection Agency (EPA) has informed the Company of its involvement or potential involvement in three hazardous waste sites. The Company has reached agreements to make de minimis financial payments related to two of the three sites in order to resolve any associated liability. If the Company is ultimately determined to be a responsible party with respect to the remaining site, it could be liable for all or a portion of the cleanup costs. However, other solvent, potentially responsible parties that may bear all or part of any liability are also involved. In addition, the Company believes that available defenses, along with other factors (including overall limited involvement and low estimated remediation costs) will limit any potential liability that the Company may have for cleanup costs. The Company believes that it is adequately reserved for all known liabilities and costs and, accordingly, that this matter will not have a materially adverse effect on its financial position or results of operations.

In 1990, Congress approved amendments to the *Clean Air Act,* which established the Emission Allowance Trading System. Allowances are issued by the EPA to fossil-fired stations with generating capability of more than 25 MW that were in existence as of the passage of the 1990 amendments. Allowances are part of an innovative market-based approach to sulfur dioxide (SO_2) reduction. Emission allowances can also be obtained through purchases on the open market or directly from other sources. Excess allowances may be banked for future use or sold on the open market to other parties to offset their emissions.

Although the Company has satisfied all of the Phase I requirements of the *Clean Air Act,* Phase II requires significant additional reductions of SO_2 and oxides of nitrogen (NO_x) by the year 2000. The Company currently has 662 MW of nuclear capacity, 1,187 MW of coal capacity equipped with SO_2 emission reducing equipment (including 300 MW of *property held for future use* at Phillips) as well as 757 MW of capacity that meets the 1995 standards of the *Clean Air Act Amendments* through the use of low sulfur coal. Through the year 2000, the Company is considering a combination of compliance methods that include fuel switching; increased use of, and improvements in, SO_2 emission reducing equipment; low NO_x burner technology; and the purchase of emission

allowances. Flue gas conditioning and post combustion NO_x reduction technologies may also be employed if economically justified. In addition, the Company is examining and developing innovative emissions technologies designed to reduce costs. The Company continues to work with the operators of its jointly owned stations to implement cost-effective compliance strategies to meet these requirements. NO_x reductions under *Title IV of the Clean Air Act* were required at Cheswick, and the work to achieve the reductions was completed in 1993. The ozone attainment provisions of *Title I of the Clean Air Act Amendments* also required NO_x reductions by mid-1995 at Cheswick, Elrama and Bruce Mansfield. The Company achieved such reductions using innovative combustion system modifications and low NO_x burner technology. The Company currently estimates that additional capital costs to comply with *Clean Air Act* requirements through the year 2000 will be approximately $20 million. This estimate is subject to the finalization of federal and state regulations and the PUC approval of the sale of the Company's interest in the Ft. Martin Power Station. (See "Sale of Ft. Martin" discussion on page 31.)

The Company has developed, patented and installed low NO_x burner technology for the Elrama boilers. These cost-effective NO_x reduction systems installed on the Elrama roof fired boilers will likely be specified as the benchmark for the industry for this class of boilers in the EPA's pending Group II rulemaking. The Company is also currently evaluating additional low cost, developmental NO_x reduction technologies at Cheswick and Elrama. An Artificial Neural Network control system enhancement, co-sponsored by the Electric Power Research Institute and the Company, will be demonstrated at Cheswick. The Gas Research Institute and the Company are sponsoring a targeted natural gas reburn demonstration at Elrama. Both demonstrations will be completed in 1996.

As required by *Title V of the Clean Air Act Amendments*, the Company has filed comprehensive air operating permit applications for Cheswick, Elrama, BI and Phillips during the last half of 1995. The Company also filed its *Title IV Phase II Clean Air Act* compliance plan with the PUC on December 27, 1995.

The Company is closely monitoring other potential future air quality programs and air emission control requirements, including additional NO_x control requirements that were recommended for fossil fuel plants by the Ozone Transport Commission and the potential for more stringent ambient air quality and emission standards for SO_2 particulates, and other by-products of coal combustion. As these potential programs are in various stages of discussion and consideration, it is impossible to make reasonable estimates of the potential costs and impacts, if any.

In 1992, the Pennsylvania Department of Environmental Protection (DEP) issued Residual Waste Management Regulations governing the generation and management of non-hazardous residual waste, such as coal ash. The Company is assessing the sites which it utilizes and has developed compliance strategies under review by the DEP. Capital compliance costs of $3.0 million were incurred by the Company in 1995 to comply with these DEP regulations; on the basis of information currently available, an additional $2.5 million will be incurred in 1996. The expected additional capital cost of compliance through the year 2000 is estimated, based on current information, to be approximately $25 million. This estimate is subject to the results of ground water assessments and DEP final approval of compliance plans.

The Company is involved in various other environmental matters. The Company believes that such matters, in total, will not have a materially adverse effect on its financial position or results of operations.

Outlook

Competition

The electric utility industry is undergoing fundamental change in response to the open transmission access and increased availability of energy alternatives fostered by NEPA which has served to increase competition in the industry. Previously captive customers are seeking freedom to choose alternative suppliers of energy. These competitive pressures require utilities to offer competitive pricing and terms to retain customers and to develop new markets for the optimal utilization of their generation capacity.

At the national level, NEPA was designed to encourage competition among electric utility companies, improve energy resource planning and to encourage the development of alternative sources of energy. NEPA authorizes the FERC to require electric utilities to provide wholesale suppliers of electric energy with nondiscriminatory access to the utility's wholesale transmission system. In response to this mandate, the FERC has issued a Notice of Proposed Rulemaking (NOPR) on Open Access Nondiscriminatory Transmission Services and a supplemental NOPR on the Recovery of Stranded Costs. The NOPR on open access transmission would define the terms under which independent power producers, neighboring utilities and others could gain access to a utility's transmission grid to deliver power to customers. The supplemental NOPR on stranded costs would address the issue of recovery of a utility's unrecovered costs that were incurred to provide service to customers that subsequently leave a utility's system in favor of another supplier. A final order is expected in mid-1996 on both NOPRs. Also, in January 1996, the FERC announced its plans to reconsider its public utility merger guidelines. The FERC actions are expected to have a significant impact on competition in the electric utility industry.

In Pennsylvania, the PUC currently is conducting an investigation concerning regulatory reform and has indicated an intention to issue a report to the governor and the Pennsylvania General Assembly by April 1996. The PUC staff issued an interim report in August 1995 that recommended that retail wheeling not be implemented at that time because of concerns that retail wheeling would benefit large industrial customers at the expense of smaller customers and utility shareholders, who would absorb the costs of stranded investments, and that service reliability could be impaired. The report concludes that performance-based ratemaking, wholesale competition and utility cost cutting could provide the benefits of retail wheeling without the attendant disruptions.

The Company is aware of the foregoing federal and state regulatory and business uncertainties, and is attempting to position itself to operate in a more competitive environment. Its current rate structure allows some flexibility in setting rates to retain its customer base and attract new business. Furthermore, as discussed below, open access transmission offers the Company the opportunity to sell power on a market basis to customers outside of its service territory.

The Company has proposals before both the FERC and the PUC that address specific issues relating to its competitive position. Because of the Company's current electric generating configuration, some of its baseload capacity is used less than optimally. Two options the Company is currently considering to align its generating capabilities more closely with customer demand are discussed in "Transmission Access" below and "Generation Resource Optimization" on page 37. First, through open transmission access, the Company is seeking to increase its level of fixed demand through the negotiation of long-term power sale contracts to customers outside its service territory. Second, the Company proposes to change its generation profile through the sale of its interest in the Ft. Martin Power Station.

As part of its petition currently before the PUC with respect to the sale of its interest in Ft. Martin, the Company has proposed, among other concessions, a five-year freeze on base rates and a five-year annual $5 million credit to the ECR (which would otherwise remain unaffected by the freeze) to compensate the Company's electric utility customers for short-term power sales foregone by the sale of its interest in the plant. (See "Sale of Ft. Martin" discussion on page 31.) Although the Company believes a rate freeze will enable it to maintain and expand its existing customer base, if the rate freeze is implemented, the Company could face the risk of reduced rates of return if unforeseen costs arise and if revenues from sales prove inadequate to fund those costs.

Finally, as noted above, open access transmission requirements implicitly create the potential for stranded costs. To address these issues, the Company has implemented, and will continue to evaluate, the accelerated depreciation of its generating assets as one method to guard against the competitive risks of stranded investments. (See "Operating Expenses" discussion on page 25.) At present, the FERC and the PUC appear supportive of stranded cost recovery; however, implementation details for recovery of stranded costs are extremely vague and far from decided. The petition for the sale of the Company's ownership interest in the Ft. Martin Power Station currently before the PUC proposes to further increase *depreciation and amortization* expense related to the Company's nuclear power investment by $75 million over a three-year period. This petition also proposes to record a one-time write-down in the value of the Company's nuclear plant investment of approximately $130 million and to increase by $5 million the annual contribution to the Company's nuclear plant decommissioning funds, for a total of $25 million in contributions over the next five years. (See "Sale of Ft. Martin" discussion on page 31.) These current and proposed accelerated investment cost recovery measures will be absorbed by the Company without an increase in base rates.

The Company believes that these and similar initiatives will strengthen its position to succeed in a more competitive environment by eliminating the need to charge its electric utility customers in the future for these currently recognized expenses. At this time, however, there is no assurance as to the extent to which Company initiatives can or will ultimately eliminate regulatory and other uncertainties associated with increased competition.

Transmission Access

In March 1994, the Company submitted, pursuant to the *Federal Power Act*, two separate "good faith" requests for transmission service with APS and the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM Companies), respectively. Each request is based on 20-year firm service with flexible delivery points for 300 MW of transfer capability over the APS and PJM Companies transmission networks, which together extend from western Pennsylvania to the East Coast. Because of a lack of progress on pricing and other issues, on August 5 and September 16, 1994, the Company filed with the FERC applications for transmission service from the PJM Companies and APS, respectively. The applications are authorized under Section 211 of the *Federal Power Act*, which requires electric utilities to provide firm wholesale transmission service. In May 1995, the FERC issued proposed orders instructing APS and the PJM Companies to provide transmission service to the Company and directing the parties to negotiate specific rates, terms and

conditions. The Company was unable to agree to terms for transmission service with either APS or the PJM Companies. Briefs were filed with the FERC outlining the areas of disagreement among the companies. The matter is now pending before the FERC. The Company cannot predict the final outcome of these proceedings.

Generation Resource Optimization

The Company's plans for optimizing generation resources are designed to reduce underutilized generating capacity, promote competition in the wholesale marketplace, maintain stable prices and meet customer-specified levels of service reliability. The Company is committed to explore firm energy sales to wholesale customers, system power sales, system power sales with specific unit back-up, unit power sales, generating asset sales and any other approach to efficiently managing capacity and energy.

The proposed sale of the Company's ownership interest in the Ft. Martin Power Station demonstrates the Company's ongoing efforts to optimize the utilization of generation resources. (See "Sale of Ft. Martin" discussion on page 31.) The sale is expected to reduce power production costs by employing a cost-effective source of peaking capacity through enhanced reliability of the simple cycle units at BI. Implementation of the proposed plan will better align the Company's generating capabilities with its native load requirements.

Customer Service Guarantees

The Company's commitment to provide reliable, quality service to its electric utility customers is characterized by its customer service guarantees. On March 6, 1995, Duquesne became the first Pennsylvania regulated utility, and the third in the United States, to offer its residential customers guarantees of its commitment to courteous, reliable and efficient service. The Company offers a $25 credit to a customer's account if it fails to provide accurate billings; to meet punctual service appointments; to extend prompt, courteous and professional service; or to connect new services within one day of the date requested by the customer.

Customer Advanced Reliability System

In January 1996, the Company announced its Customer Advanced Reliability System, a new communications service that will provide its electric utility customers with superior levels of service reliability, security and convenience. The Company has signed a long-term, full service contract with Itron, Inc. (Itron), a leading supplier of energy information and communication solutions to the electric utility industry. Over the next two years, Itron will install, operate and maintain a communications network that will provide the Company with an electronic link to its 580,000 customers.

The Customer Advanced Reliability System is designed to respond to customer needs on the basis of immediate information about the status of power delivery at individual homes and businesses. This electronic communications service is another major element in the Company's multi-step plan to make the Company's electric utility operations more competitive and efficient.

Other

Financial Accounting Pronouncement

The Financial Accounting Standards Board issued *Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of (SFAS No. 121)* in March 1995. This statement is effective for years beginning after December 15, 1995. The Company anticipates adopting this standard on January 1, 1996, and does not expect that it will have a material impact on its financial position or results of operations, based on the current regulatory structure in which it operates. As competitive factors influence pricing in the utility industry, this opinion may change in the future. The general requirements of *SFAS No. 121* apply to non-current assets and require impairment to be considered whenever evidence suggests that it is no longer probable that future cash flows in an amount at least equal to the asset will result.

Retirement Plan Measurement Assumptions

The Company decreased the discount rate used to determine the projected benefit obligation on the Company's retirement plans at December 31, 1995, to 7.0 percent. The assumed change in future compensation levels was also decreased to reflect current market and economic conditions. The effects of these changes on the Company's retirement plan obligations are reflected in the amounts shown in "Employee Benefits," Note N, to the consolidated financial statements on page 57. The resulting change in related expenses for subsequent years is not expected to be material.

Except for historical information contained herein, the matters discussed in this annual report are forward-looking statements which involve risks and uncertainties including, but not limited to, economic, competitive, governmental and technological factors affecting the Company's operations, markets, products, services and prices and other factors discussed in the Company's filings with the Securities and Exchange Commission.

Report of Independent Certified Public Accountants

To the Directors and Shareholders of DQE:

We have audited the accompanying consolidated balance sheet of DQE and its subsidiaries as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1995. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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, such consolidated financial statements present fairly, in all material respects, the financial position of DQE and its subsidiaries as of December 31, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995 in conformity with generally accepted accounting principles.

As discussed in Note A to the consolidated financial statements, effective January 1, 1993, the Company changed its method of accounting for income taxes to conform with Statement of Financial Accounting Standards No. 109, and the Company changed its method of accounting for maintenance costs during scheduled major fossil station outages.

Deloitte & Touche LLP

Deloitte & Touche LLP
Pittsburgh, Pennsylvania
January 30, 1996

Report of the Audit Committee of the Board of Directors of DQE

The Audit Committee, composed entirely of non-employee directors, meets regularly with the independent certified public accountants and the internal auditors to discuss results of their audit work, their evaluation of the adequacy of the internal accounting controls and the quality of financial reporting.

In fulfilling its responsibilities in 1995, the Audit Committee recommended to the Board of Directors, subject to shareholder approval, the selection of the Company's independent certified public accountants. The Audit Committee reviewed the overall scope and details of the independent certified public accountants' and internal auditors' respective audit plans and reviewed and approved the independent certified public accountants' general audit fees and non-audit services.

Audit Committee meetings are designed to facilitate open communications with internal auditors and independent certified public accountants. To ensure auditor independence, both the independent certified public accountants and the internal auditors have full and free access to the Audit Committee.

The Audit Committee of the Board of Directors of DQE

Statement of Consolidated Income

		(Thousands of Dollars, Except Per Share Amounts) Year Ended December 31, 1995	1994	1993
Operating Revenues	Sales of Electricity:			
	Customers - net	$1,083,339	$1,104,327	$1,169,685
	Phase-in deferrals	—	(28,810)	(100,315)
	Net customer revenues	1,083,339	1,075,517	1,069,370
	Utilities	55,963	58,295	50,669
	Total Sales of Electricity	1,139,302	1,133,812	1,120,039
	Other	80,860	90,098	63,141
	Total Operating Revenues	1,220,162	1,223,910	1,183,180
Operating Expenses	Fuel and purchased power	231,968	244,135	237,731
	Other operating	303,216	328,479	328,108
	Maintenance	81,516	79,488	80,292
	Depreciation and amortization	192,339	166,610	152,673
	Taxes other than income taxes	88,658	88,331	71,371
	Total Operating Expenses	897,697	907,043	870,175
Operating Income	**Operating Income**	322,465	316,867	313,005
Other Income	**Other Income**	52,314	42,924	27,879
Interest and Other Charges	**Interest and Other Charges**	107,555	110,002	119,655
	Income Before Income Taxes	267,224	249,789	221,229
Income Taxes	**Income Taxes**	96,661	92,973	79,822
	Income Before Cumulative Effect on Prior Years of Changes in Accounting Principles	170,563	156,816	141,407
	Adoption of *SFAS No. 109* - income taxes	—	—	8,000
	Accounting for maintenance costs - net	—	—	(5,425)
Net Income	**Net Income**	$ 170,563	$ 156,816	$ 143,982
	Average Number of Common Shares Outstanding (Thousands of Shares)	77,674	79,046	79,469
Earnings Per Share	**Earnings Per Share of Common Stock:**			
	Income Before Cumulative Effect on Prior Years of Changes in Accounting Principles	$2.20	$1.98	$1.78
	Adoption of *SFAS No. 109* - income taxes	—	—	.10
	Accounting for maintenance costs - net	—	—	(.07)
	Earnings Per Share of Common Stock	$2.20	$1.98	$1.81
Dividends Declared	**Dividends Declared Per Share of Common Stock**	$1.21	$1.13	$1.08

See notes to consolidated financial statements.

Consolidated Balance Sheet

		(Thousands of Dollars) As of December 31,	
		1995	1994
Assets	**Current Assets:**		
	Cash and temporary cash investments	$ 24,767	$ 50,058
	Receivables:		
	Electric customer accounts receivable	103,821	96,157
	Other utility receivables	22,441	26,008
	Other receivables	25,164	53,766
	Less: Allowance for uncollectible accounts	(18,658)	(15,822)
	Receivables less allowance for uncollectible accounts	132,768	160,109
	Less: Receivables sold	(7,000)	—
	Total Receivables	125,768	160,109
	Materials and supplies (at average cost):		
	Coal	25,454	30,484
	Operating and construction	53,298	58,262
	Total Materials and Supplies	78,752	88,746
	Other current assets	8,099	36,156
	Total Current Assets	237,386	335,069
	Long-Term Investments:		
	Affordable housing	116,784	57,497
	Natural gas reserves	69,435	—
	Leveraged leases	87,834	50,322
	Other leases	106,916	53,256
	Other	59,947	35,143
	Total Long-Term Investments	440 916	196,218
	Property, Plant and Equipment:		
	Electric plant in service	4,265,161	4,196,690
	Construction work in progress	38,134	52,199
	Property held under capital leases	133,381	162,732
	Property held for future use	216,633	216,206
	Other	92,804	81,697
	Total	4,746,113	4,709,524
	Less accumulated depreciation and amortization	(1,685,877)	(1,569,983)
	Property, Plant and Equipment – Net	3,060,236	3,139,541
	Other Non-Current Assets:		
	Regulatory assets	671,928	710,763
	Other	48,377	45,414
	Total Other Non-Current Assets	720,305	756,177
	Total Assets	$4,458,843	$4,427,005

See notes to consolidated financial statements.

Liabilities and Capitalization

	(Thousands of Dollars)	
	As of December 31,	
	1995	1994
Current Liabilities:		
Notes payable	$ 35,098	$ 60,115
Current maturities and sinking fund requirements	71,379	85,986
Accounts payable	90,941	83,854
Accrued liabilities	52,063	64,894
Dividends declared	27,825	26,484
Other	9,191	5,722
Total Current Liabilities	286,497	327,055
Non-Current Liabilities:		
Deferred income taxes – net	801,631	969,948
Deferred investment tax credits	115,760	123,591
Capital lease obligations	34,546	41,106
Deferred income	221,740	64,113
Other	197,973	151,526
Total Non-Current Liabilities	1,371,650	1,350,284
Commitments and Contingencies (Notes B through N)		
Capitalization:		
Long-Term Debt	1,400,993	1,377,611
Preferred and Preference Stock of Subsidiaries:		
Non-redeemable preferred stock	63,608	90,340
Non-redeemable preference stock	29,615	29,857
Total preferred and preference stock before deferred ESOP benefit (involuntary liquidation values of $93,086 and $120,060 exceed par by $28,781 and $43,882, respectively)	93,223	120,197
Deferred employee stock ownership plan (ESOP) benefit	(22,257)	(24,852)
Total Preferred and Preference Stock of Subsidiaries	70,966	95,345
Common Shareholders' Equity:		
Common stock – no par value (authorized – 187,500,000 shares; issued – 109,679,154 shares)	997,461	1,001,973
Retained earnings	698,986	622,072
Treasury stock (at cost) (32,123,601 and 31,220,547 shares)	(367,710)	(347,335)
Total Common Shareholders' Equity	1,328,737	1,276,710
Total Capitalization	2,800,696	2,749,666
Total Liabilities and Capitalization	$4,458,843	$4,427,005

Statement of Consolidated Cash Flows

		(Thousands of Dollars) Year Ended December 31, 1995	1994	1993
Cash Flows from Operating Activities	Net income	$170,563	$156,816	$143,982
	Principal non-cash charges (credits) to net income:			
	Depreciation and amortization	192,339	166,610	152,673
	Capital lease, nuclear fuel and other amortization	38,847	36,320	32,019
	Deferred income taxes and investment tax credits – net	(22,122)	(11,842)	(39,736)
	Allowance for equity funds used during construction	(721)	(1,295)	(869)
	Phase-in revenues and carrying charges recovered	—	28,621	99,375
	Changes in working capital other than cash	46,527	(31,891)	(111,677)
	Other – net	28,618	26,288	23,582
	Net Cash Provided from Operating Activities	454,051	369,627	299,349
Cash Flows Used by Investing Activities	Investments:			
	Capital expenditures	(94,164)	(121,085)	(124,376)
	Long-term investments	(187,719)	(66,698)	(71,956)
	Total Capital Expenditures and Long-Term Investments	(281,883)	(187,783)	(196,332)
	Other – net	(3,854)	(12,321)	(5,178)
	Net Cash Used by Investing Activities	(285,737)	(200,104)	(201,510)
Cash Flows Used in Financing Activities	Issuance of long-term debt	65,000	114,110	740,500
	(Decrease) increase in notes payable	(20,236)	32,530	36,267
	Dividends on common stock	(93,649)	(89,348)	(86,089)
	Repurchase of common stock	(21,271)	(23,307)	—
	Reductions of long-term obligations:			
	Preferred and preference stock	(29,732)	(39,958)	(187)
	Long-term debt	(56,114)	(114,835)	(735,048)
	Other obligations	(26,373)	(33,522)	(27,751)
	Premium on reacquired debt	(1,731)	(5,033)	(31,702)
	Other – net	(9,499)	7,664	623
	Net Cash Used in Financing Activities	(193,605)	(151,699)	(103,387)
	Net (decrease) increase in cash and temporary cash investments	(25,291)	17,824	(5,548)
	Cash and temporary cash investments at beginning of year	50,058	32,234	37,782
	Cash and temporary cash investments at end of year	$ 24,767	$ 50,058	$ 32,234

Supplemental Cash Flow Information

		1995	1994	1993
Cash Paid During the Year	Interest (net of amount capitalized)	$ 99,954	$105,900	$125,304
	Income taxes	$ 115,504	$ 111,614	$133,303
Non-Cash Investing and Financing Activities	Capital lease obligations recorded	$ 14,961	$ 16,909	$ 11,811
	Equity funding obligations recorded	$ 21,827	—	—
	Preferred stock issued in conjunction with long-term investments	$ 3,000	—	—

See notes to consolidated financial statements.

STATEMENT OF CONSOLIDATED RETAINED EARNINGS

	(Thousands of Dollars)		
	1995	1994	1993
Balance at beginning of year	$622,072	$554,604	$496,711
Net income	170,563	156,816	143,982
Dividends declared	(93,649)	(89,348)	(86,089)
Balance at end of year	$698,986	$622,072	$554,604

See notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. Summary of Significant Accounting Policies

Consolidation

DQE is an energy services holding company. Its subsidiaries are Duquesne Light Company (Duquesne), Duquesne Enterprises (DE), DQE Energy Services (DES) and Montauk. DQE and its subsidiaries are collectively referred to as the Company.

Duquesne is an electric utility engaged in the production, transmission, distribution and sale of electric energy, and the largest of DQE's subsidiaries. DE makes strategic investments related to DQE's core energy business. These investments enhance DQE's capabilities as an energy provider, increase asset utilization, and act as a hedge against changing business conditions. DES was formed in August 1995 and is a marketing and development company providing energy solutions for customers in domestic and international markets. Montauk is a financial services company that makes long-term investments and provides financing for the Company's initiatives in high quality products, services and energy solutions for its customers.

All material intercompany balances and transactions have been eliminated in the preparation of the consolidated financial statements of DQE.

Basis of Accounting

The Company is subject to the accounting and reporting requirements of the Securities and Exchange Commission (SEC). In addition, the Company's electric utility operations are subject to the regulation of the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC). As a result, the consolidated financial statements contain regulatory assets and liabilities in accordance with *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71)* and reflect the effects of the ratemaking process. Such effects concern mainly the time at which various items enter into the determination of net income in accordance with the principle of matching costs and revenues. (See "Rate Matters," Note F, on page 48.)

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. The reported amounts of revenues and expenses during the reporting period may also be affected by the estimates and assumptions management is required to make. Actual results could differ from those estimates.

Revenues

Meters are read monthly and customers are billed on the same basis. Revenues are recorded in the accounting periods for which they are billed, with the exception of energy cost recovery revenues. Deferred revenues are associated with the Company's 1987 rate case. (See "Energy Cost Rate Adjustment Clause (ECR)" discussion on page 44 and "1987 Rate Case" discussion, Note F, on page 48).

The Company's Electric Service Territory

The Company's utility operations provide electric service to customers in Allegheny County including the City of Pittsburgh, and Beaver County. This represents a service territory of approximately 800 square miles in southwestern Pennsylvania. The population of the area served by the Company's electric utility operations, based on 1990 census data, is approximately 1,510,000, of whom 370,000 reside in the City of Pittsburgh. In addition to serving approximately 580,000 customers within this service area, the Company's utility operations also sell electricity to other utilities beyond the Company's service territory.

Net Customer Revenues for the year ended December 31

	1995	1994	1993
	(Amounts in Thousands of Dollars)		
Sales of Electricity:			
Customers	$1,096,769	$1,116,217	$1,186,779
Provision for doubtful accounts	(13,430)	(11,890)	(17,094)
Customers - net	1,083,339	1,104,327	1,169,685
Phase-in deferrals	—	(28,810)	(100,315)
Net Customer Revenues	$1,083,339	$1,075,517	$1,069,370

Energy Cost Rate Adjustment Clause (ECR)

Through the ECR, the Company recovers (to the extent that such amounts are not included in base rates) nuclear fuel, fossil fuel and purchased power expenses and, also through the ECR, passes to its customers the profits from short-term power sales to other utilities (collectively, ECR energy costs). Nuclear fuel expense is recorded on the basis of the quantity of electric energy generated and includes such costs as the fee imposed by the United States Department of Energy (DOE) for future disposal and ultimate storage and disposition of spent nuclear fuel. Fossil fuel expense includes the costs of coal, natural gas and fuel oil used in the generation of electricity.

On the Company's statement of consolidated income, these energy cost recovery revenues are included as a component of *operating revenues*. For ECR purposes, the Company defers fuel and other energy expenses for recovery, or refunding, in subsequent years. The deferrals reflect the difference between the amount that the Company is currently collecting from customers and its actual ECR energy costs. The PUC annually reviews the Company's ECR energy costs for the fiscal year April through March, compares them to previously projected ECR energy costs and adjusts the ECR for over- or under-recoveries and for two PUC-established coal cost standards. (See "Deferred Coal Costs" and "Warwick Mine Costs" discussions, Note F, on page 49.)

Over- or under-recoveries from customers are recorded in the consolidated balance sheet as payable to, or receivable from, customers. At December 31, 1995, $5.8 million was payable to customers and shown as *other current liabilities*. At December 31, 1994, $5.9 million was receivable from customers and shown as *other current assets*.

Maintenance

Incremental *maintenance* expense incurred for refueling outages at the Company's nuclear units is deferred for amortization over the period between refueling outages (generally 18 months). The Company changed, as of January 1, 1993, its method of accounting for maintenance costs during scheduled major fossil generating station outages. Prior to that time, maintenance costs incurred for scheduled major outages at fossil generating stations were charged to expense as these costs were incurred. Under the new accounting policy, the Company accrues, over the periods between outages, anticipated expenses for scheduled major fossil generating station outages. Maintenance costs incurred for non-major scheduled outages and for forced outages are charged to expense as such costs are incurred. This method was adopted to match more accurately the maintenance costs and the revenue produced during the periods between scheduled major fossil generating station outages.

The cumulative effect (approximately $5.4 million, net of income taxes of approximately $3.9 million) of the change on prior years was included in *net income* in 1993. The effect of the change in 1993 was to reduce *income, before the cumulative effect of changes in accounting principles*, by approximately $2.4 million, or $.03 per share, and to reduce *net income*, after the cumulative effect of changes in accounting principles, by approximately $7.8 million, or $.10 per share, based on post-split shares.

Depreciation and Amortization

Depreciation of *property, plant and equipment*, including plant-related intangibles, is recorded on a straight-line basis over the estimated remaining useful lives of properties. Amortization of other intangibles is recorded on a straight-line basis over a five-year period. Depreciation and amortization of other properties are calculated on various bases.

The Company records decommissioning costs under the category of *depreciation and amortization* expense and accrues a liability, equal to that amount, for nuclear decommissioning expense. Such nuclear decommissioning funds are deposited in external, segregated trust accounts. The funds are invested in a portfolio of municipal bonds, certificates of deposit and United States government securities. Trust fund earnings increase the fund balance and the recorded liability. The market value of the aggregate trust fund balances at December 31, 1995, totaled approximately

Statement of Consolidated Retained Earnings

	(Thousands of Dollars)		
	1995	1994	1993
Balance at beginning of year	$622,072	$554,604	$496,711
Net income	170,563	156,816	143,982
Dividends declared	(93,649)	(89,348)	(86,089)
Balance at end of year	$698,986	$622,072	$554,604

See notes to consolidated financial statements.

Notes to Consolidated Financial Statements

A. Summary of Significant Accounting Policies

Consolidation

DQE is an energy services holding company. Its subsidiaries are Duquesne Light Company (Duquesne), Duquesne Enterprises (DE), DQE Energy Services (DES) and Montauk. DQE and its subsidiaries are collectively referred to as the Company.

Duquesne is an electric utility engaged in the production, transmission, distribution and sale of electric energy, and the largest of DQE's subsidiaries. DE makes strategic investments related to DQE's core energy business. These investments enhance DQE's capabilities as an energy provider, increase asset utilization, and act as a hedge against changing business conditions. DES was formed in August 1995 and is a marketing and development company providing energy solutions for customers in domestic and international markets. Montauk is a financial services company that makes long-term investments and provides financing for the Company's initiatives in high quality products, services and energy solutions for its customers.

All material intercompany balances and transactions have been eliminated in the preparation of the consolidated financial statements of DQE.

Basis of Accounting

The Company is subject to the accounting and reporting requirements of the Securities and Exchange Commission (SEC). In addition, the Company's electric utility operations are subject to the regulation of the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC). As a result, the consolidated financial statements contain regulatory assets and liabilities in accordance with *Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71)* and reflect the effects of the ratemaking process. Such effects concern mainly the time at which various items enter into the determination of net income in accordance with the principle of matching costs and revenues. (See "Rate Matters," Note F, on page 48.)

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. The reported amounts of revenues and expenses during the reporting period may also be affected by the estimates and assumptions management is required to make. Actual results could differ from those estimates.

Revenues

Meters are read monthly and customers are billed on the same basis. Revenues are recorded in the accounting periods for which they are billed, with the exception of energy cost recovery revenues. Deferred revenues are associated with the Company's 1987 rate case. (See "Energy Cost Rate Adjustment Clause (ECR)" discussion on page 44 and "1987 Rate Case" discussion, Note F, on page 48).

The Company's Electric Service Territory

The Company's utility operations provide electric service to customers in Allegheny County, including the City of Pittsburgh, and Beaver County. This represents a service territory of approximately 800 square miles in southwestern Pennsylvania. The population of the area served by the Company's electric utility operations, based on 1990 census data, is approximately 1,510,000, of whom 370,000 reside in the City of Pittsburgh. In addition to serving approximately 580,000 customers within this service area, the Company's utility operations also sell electricity to other utilities beyond the Company's service territory.

$28.5 million. On the Company's consolidated balance sheet, the decommissioning trusts have been reflected in *other long-term investments*, and the related liability has been recorded as *other non-current liabilities*. (See "Nuclear Decommissioning" discussion, Note J, on page 52.)

Depreciation and amortization expense increased $25.7 million primarily due to the change in Duquesne's composite depreciation rate from 3.0 percent to 3.5 percent effective January 1, 1995.

Income Taxes

On January 1, 1993, the Company adopted *Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS No. 109)*. Implementation of *SFAS No. 109* involved a change in accounting principle. The cumulative $8 million effect on prior years was reported in 1993 as an increase in *net income*.

SFAS No. 109 requires that the liability method be used in computing deferred taxes on all differences between book and tax bases of assets. These book/tax differences occur when events and transactions recognized for financial reporting purposes are not recognized in the same period for tax purposes. *SFAS No. 109* also requires that a deferred tax liability or asset be adjusted in the period of enactment for the effect of changes in tax laws or rates. During 1994, the statutory Pennsylvania income tax rate was reduced from 12.25 percent to 9.99 percent. This resulted in a net decrease of $80.5 million in deferred tax liabilities and a corresponding reduction in the regulatory receivable.

For its electric utility operations, the Company recognizes a *regulatory asset* for the deferred tax liabilities that are expected to be recovered from customers through rates. (See "Rate Matters," Note F, and "Income Taxes," Note H, on pages 48 and 50, respectively.)

With respect to the financial statement presentation of *SFAS No. 109*, the Company reflects the amortization of the regulatory tax receivable resulting from reversals of deferred taxes as *depreciation and amortization* expense. Reversals of accumulated *deferred income taxes* are included in *income tax* expense.

When applied to reduce the Company's income tax liability, investment tax credits related to electric utility property generally were deferred. Such credits are subsequently reflected, over the lives of the related assets, as reductions to tax expense.

Property, Plant and Equipment

The asset values of the Company's electric utility properties are stated at original construction cost, which includes related payroll taxes, pensions and other fringe benefits, as well as administrative and general costs. Also included in original construction cost is an allowance for funds used during construction (AFC), which represents the estimated cost of debt and equity funds used to finance construction. The amount of AFC that is capitalized will vary according to changes in the cost of capital and in the level of construction work in progress (CWIP). On a current basis, the Company does not realize cash from the AFC. The Company does realize cash, during the service life of the plant, through increased revenues reflecting a higher rate base (upon which a return is earned) and increased depreciation. The AFC rates applied to CWIP were 8.7 percent in 1995, 9.0 percent in 1994 and 9.6 percent in 1993.

Additions to, and replacements of, property units are charged to plant accounts. Maintenance, repairs and replacement of minor items of property are recorded as expenses when they are incurred. The costs of electric utility properties that are retired (plus removal costs and less any salvage value) are charged to *accumulated depreciation and amortization*.

Substantially all of the Company's electric utility properties are subject to a first mortgage lien.

Other Current Assets and Long-Term Investments

The Company's *other current assets* and *long-term investments* include certain investments in marketable securities. In accordance with *Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities (SFAS No. 115)*, these investments are classified as available-for-sale and are stated at market value.

Financial Accounting Pronouncement

The Financial Accounting Standards Board issued *Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of (SFAS No. 121)* in March 1995. This statement is effective for years beginning after December 15, 1995. The Company anticipates adopting this standard on January 1, 1996, and does not expect that it will have a material impact on its financial position or results of operations, based on the current regulatory structure in which it operates. As competitive factors influence pricing in the utility industry, this opinion may change in the future. The general requirements of *SFAS No. 121* apply to non-current assets and require impairment to be considered whenever evidence suggests that it is no longer probable that future cash flows in an amount at least equal to the asset will result.

Temporary Cash Investments

Temporary cash investments are short-term, highly liquid investments with original maturities of three or fewer months. They are stated at market, which approximates cost. The Company considers temporary cash investments to be cash equivalents.

Reclassifications

The 1994 and 1993 consolidated financial statements have been reclassified to conform with accounting presentations adopted during 1995.

B. Receivables

The Company and an unaffiliated corporation have an agreement that entitles the Company to sell, and the corporation to purchase, on an ongoing basis, up to $50 million of accounts receivable. At December 31, 1995, the Company had sold $7 million of receivables to the unaffiliated corporation. The Company had no receivables sold at December 31, 1994. The accounts receivable sales agreement, which expires in June 1996, is one of many sources of funds available to the Company. The Company may attempt to extend the agreement, or to replace the facility with a similar one or to eliminate it upon expiration.

C. Changes in Working Capital Other than Cash

Changes in Working Capital Other than Cash

	1995	1994	1993 (a)
	(Amounts in Thousands of Dollars)		
Receivables	$34,341	$ 9,928	$(103,188)
Materials and supplies	9,994	2,932	13,635
Other current assets	3,126	(25,701)	4,631
Accounts payable	7,087	(4,455)	(7,961)
Other current liabilities	(8,021)	(14,595)	(18,794)
Total	$46,527	$(31,891)	$(111,677)

(a) Net of the effects from the purchase of Chester Engineers (Chester)

D. Long-Term Investments

The Company makes equity investments in affordable housing and natural gas reserve partnerships as a limited partner. At December 31, 1995, the Company had investments in twenty-one affordable housing funds, eight of which were made during 1995, and two natural gas reserve partnerships, each of which were made during the year.

Deferred income primarily relates to the Company's leasehold investments. Deferred amounts will be recognized as income over the lives of the underlying leasehold investments over periods generally not exceeding five years.

The Company is the lessor in six leveraged lease arrangements involving manufacturing equipment, mining equipment, rail equipment, a fossil generating station and natural gas processing equipment. These leases expire in various years beginning in 2001 through 2033. The residual value of the equipment at the end of the lease terms is estimated to approximate 6 percent of the original cost. The Company's aggregate investment represents 18 percent of the aggregate original cost of the property and is secured by guarantees of each lessee's parent or affiliate. The remaining 82 percent was financed by non-recourse debt provided by lenders who have been granted, as their sole remedy in the event of default by the lessees, an assignment of rentals due under the leases and a security interest in the leased property. This debt amounted to $364 million and $139 million at December 31, 1995 and 1994, respectively.

Net Leveraged Lease Investments at December 31

	1995	1994
	(Amounts in Thousands of Dollars)	
Rentals receivable (net of principal and interest on the non-recourse debt)	$113,641	$50,010
Estimated residual value of leased assets	26,470	26,470
Less: Unearned income	(52,277)	(26,158)
Leveraged lease investments	87,834	50,322
Less: Deferred taxes arising from leveraged leases	(42,392)	(34,174)
Net Leveraged Lease Investments	$ 45,442	$16,148

The Company's other leases include investments in fossil generating stations, a waste-to-energy facility, computers, vehicles and equipment. The Company's other investments are primarily in assets of nuclear decommissioning trusts and marketable securities, primarily of Exide Electronics

Group, Inc. In accordance with *SFAS No. 115*, these investments are classified as available-for-sale and are stated at market value. The amount of unrealized holding losses related to marketable securities at December 31, 1995, is $4.4 million ($2.6 million net of tax). There were no material unrealized gains or losses on investments at December 31, 1994.

E. Property, Plant and Equipment

In addition to its wholly owned generating units, the Company, together with other electric utilities, has an ownership or leasehold interest in certain jointly owned units. The Company is required to pay its share of the construction and operating costs of the units. The Company's share of the operating expenses of the units is included in the statement of consolidated income.

Generating Units at December 31, 1995

Unit	Megawatts (h)	Net Utility Plant *(Millions of Dollars)*	Fuel Source
Cheswick	570	$ 118.7	Coal
Elrama (a)	487	98.1	Coal
Ft. Martin Unit 1 (b)	276	36.4	Coal
Eastlake Unit 5	186	42.7	Coal
Sammis Unit 7	187	53.1	Coal
Bruce Mansfield Unit 1 (a)	228	66.2	Coal
Bruce Mansfield Unit 2 (a)	62	19.1	Coal
Bruce Mansfield Unit 3 (a)	110	52.1	Coal
Beaver Valley Unit 1 (c)	385	234.0	Nuclear
Beaver Valley Unit 2 (d)(e)	113	14.4	Nuclear
Beaver Valley Common Facilities		159.4	
Perry Unit 1 (f)	164	565.5	Nuclear
Brunot Island	66	7.1	Fuel Oil
Total	2,834	1,466.8	
Property held for future use:			
Brunot Island (g)	240	44.9	Fuel Oil
Phillips (a)	300	77.4	Coal
Total Generating Units	3,374	$1,589.1	

(a) The unit is equipped with flue gas desulfurization equipment.
(b) See "Sale of Ft. Martin" discussion below.
(c) The Nuclear Regulatory Commission (NRC) has granted a license to operate through January 2016.
(d) On October 2, 1987, the Company sold its 13.74 percent interest in Beaver Valley Unit 2 (BV Unit 2) and leased it back; the sale was exclusive of transmission and common facilities. Amounts shown represent facilities not sold and subsequent leasehold improvements.
(e) The NRC has granted a license to operate through May 2027.
(f) The NRC has granted a license to operate through March 2026.
(g) Idle combustion turbine capacity representing 168 megawatts may be returned to service pending outcome of the sale of Ft. Martin. (See "Sale of Ft. Martin" discussion below.)
(h) Generating capability during the winter season.

Sale of Ft. Martin

In December 1995, the Company filed a Petition for Declaratory Order with the PUC requesting approval for the sale of its ownership interest in the Ft. Martin Power Station and for a six-point plan to be financed in part by the proceeds of the Ft. Martin transaction. Under the plan, the Company offers to freeze its base rates for a period of five years. In addition, the Company proposes to record a one-time reduction of approximately $130 million in the value of the Company's nuclear plant investment. The Company also proposes to use the proceeds from the sale to finance reliability enhancements to the simple cycle units located at Brunot Island (BI), to retire debt and to reduce equity. The plan also proposes an annual increase of $25 million for three years in *depreciation and amortization* expense to the Company's nuclear investment, as well as additional annual contributions to its nuclear plant decommissioning funds of $5 million for five years, without any increase in existing electric rates. Lastly, the Company proposes a five-year annual $5 million credit to the ECR to compensate the Company's electric utility customers for the lost profits from any reduced short-term power sales foregone by the sale of its ownership interest in the Ft. Martin Power Station. (See "Energy Cost Rate Adjustment Clause (ECR)" discussion, Note A, on page 44.) The PUC is currently reviewing the Company's petition.

1987 Rate Case

In March 1988, the PUC adopted a rate order that increased the Company's electric utility revenues by $232 million annually. This rate increase was phased-in from April 1988 through April 1994. Deficiencies in current revenues which resulted from the phase-in plan were included in the consolidated statement of income as *phase-in deferrals*. *Phase-in deferrals* were recorded on the consolidated balance sheet as a *regulatory asset*. As customers were billed for deficiencies related to prior periods, this regulatory asset was reduced.

At this time, the Company has no pending base rate case and has no immediate plans to file a base rate case. In the Company's petition cu[illegible]ently before the PUC for the sale of its ownership interest in the Ft. Martin Power Station, the Company proposes to freeze its base rates for a five-year period. (See "Sale of Ft. Martin" discussion, Note E, on page 47.)

Regulatory Assets

As a result of the application of *SFAS No. 71*, the Company records *regulatory assets* on its consolidated balance sheet. The *regulatory assets* represent probable future revenue to the Company because provisions for these costs are currently included, or are expected to be included, in charges to electric utility customers through the ratemaking process.

The Company's electric utility operations currently satisfy the *SFAS No. 71* criteria. However, a company's electric utility operations or a portion of such operations could cease to meet these criteria for various reasons, including a change in the PUC or the FERC regulations. Should the Company's electric utility operations cease to meet the *SFAS No. 71* criteria, the Company would be required to write off any regulatory assets or liabilities for those operations that no longer meet these requirements. Management will continue to evaluate significant changes in the regulatory and competitive environment in order to assess the Company's overall consistency with the criteria of *SFAS No. 71*.

Regulatory Assets at December 31

	1995	1994
	(Amounts in Thousands of Dollars)	
Regulatory tax receivable (Note H)	$414,543	$428,043
Unamortized debt costs (Note K)(a)	98,776	103,454
Deferred rate synchronization costs (see below)	51,149	51,149
Beaver Valley Unit 2 (BV Unit 2) sale/leaseback premium (Note I)(b)	31,564	[illegible],414
Deferred employee costs (c)	31,218	[illegible]012
Extraordinary property loss (see below)	8,300	[illegible]394
Deferred nuclear maintenance outage costs (Note A)	6,776	[illegible]06
DOE decontamination and decommissioning receivable (Note J)	10,687	1[illegible],[illegible]32
Deferred coal costs (see page 49)	12,753	10,677
Other	6,162	8,282
Total Regulatory Assets	$671,928	$710,763

(a) The premiums paid to reacquire debt prior to scheduled maturity dates are deferred for amortization over the life of the debt issued to finance the reacquisitions.
(b) The premium paid to refinance the BV Unit 2 lease was deferred for amortization over the life of the lease.
(c) Includes amounts for recovery of accrued compensated absences and accrued claims for workers' compensation.

Deferred Rate Synchronization Costs

In 1987, the PUC approved the Company's petition to defer initial operating and other costs of Perry Unit 1 and BV Unit 2. The Company deferred the costs incurred from November 17, 1987, when the units went into commercial operation, until March 25, 1988, when a rate order was issued. In its order, the PUC postponed ruling on whether these costs would be recoverable from the Company's electric utility customers. The Company is not earning a return on the deferred costs. The Company believes that these deferred costs are recoverable. In 1990 and 1995, the PUC permitted other Pennsylvania electric utilities rate recovery of such costs.

Extraordinary Property Loss

The Company abandoned its interest in the partially constructed Perry Unit 2 in 1986 and subsequently disposed of its interest in 1992. In the 1987 rate case, the PUC approved recovery, over a 10-year period, of the Company's original $155 million investment in Perry Unit 2. The Company is not earning a return on the as-yet-unrecovered portion of its investment in the unit.

Deferred Coal Costs

The PUC has established two market price coal cost standards. One applies only to coal delivered at the Bruce Mansfield Power Station (Bruce Mansfield). The other, the system-wide coal cost standard, applies to coal delivered to the remainder of the Company's system. Both standards are updated monthly to reflect prevailing market prices for similar coal. The PUC has directed the Company to defer recovery of the delivered cost of coal to the extent that such cost exceeds generally prevailing market prices for similar coal, as determined by the PUC. The PUC allows deferred amounts to be recovered from customers when the delivered costs of coal fall below such PUC-determined prevailing market prices.

In 1990, the PUC approved a joint petition for settlement that clarified certain aspects of the system-wide coal cost standard and gave the Company options to extend the standard through March 2000. In December 1991, the Company exercised the first of two options that extended the standard through March 1996. In December 1995, the Company exercised the second option to extend the standard through March 2000. The unrecovered cost of coal used at Bruce Mansfield amounted to $8.4 million and $7.3 million and the unrecovered cost of coal used throughout the system amounted to $4.4 million and $3.4 million at December 31, 1995 and 1994, respectively. The Company believes that all deferred coal costs will be recovered.

Warwick Mine Costs

The 1990 joint petition for settlement (See preceding discussion on "Deferred Coal Costs.") also recognized costs at the Company's Warwick Mine, which had been on standby since 1988, and allowed for recovery of such costs, including the costs of ultimately closing the mine. In 1990, the Company entered into an agreement under which an unaffiliated company will operate the mine until March 2000 and sell the coal produced. Production began in late 1990. The mine reached a full production rate in early 1991. The Warwick Mine coal reserves include both high and low sulfur coal; the Company's contract is for medium to high sulfur (1.3 percent to 2.5 percent) coal. More than 60 percent of the coal mined at Warwick Mine currently is used by the Company. The Company receives a royalty on sales of Warwick coal in the open market. These royalties are credited to the Company's ECR. In the past year, the Warwick Mine supplied slightly less than one-fifth of the coal used in the production of electricity at the Company's wholly owned and jointly owned plants.

Costs at the Warwick Mine and the Company's investment in the mine are expected to be recovered through the cost of coal in the ECR. Recovery is subject to the system-wide coal cost standard. The Company also has an opportunity to earn a return on its investment in the mine through the cost of coal during the period of the system-wide coal cost standard including extensions. At December 31, 1995, the Company's net investment in the mine was $14.9 million. The current estimated liability, including final site reclamation, mine water treatment and certain labor liabilities, for mine closing is $34.1 million and the Company has recorded a liability on the consolidated balance sheet of approximately $15.9 million toward these costs.

Property Held for Future Use

In 1986, the PUC approved the Company's request to remove the 300 MW Phillips Power Station (Phillips) and 240 MW of BI from service and from rate base. The Company expects to recover its net investment in these plants through future electricity sales. The Company believes its investment in these plants will be necessary in order to meet future business needs outlined in the Company's plans for optimizing generation resources. If business opportunities do not develop as expected, the Company will consider the sale of these assets. In the event that market demand, transmission access or rate recovery do not support the utilization or sale of the plants, the Company may have to write off part or all of their costs. At December 31, 1995, the Company's net investment in Phillips and BI held for future use was $77.4 million and $44.9 million, respectively.

G. Short-Term Borrowing and Revolving Credit Arrangements

At December 31, 1995, the Company had two extendible revolving credit agreements, including a $100 million facility expiring in August 1996 and a $150 million facility expiring in October 1996. Interest rates on these credit agreements vary. Commitment fees are based on the unborrowed amount of the commitments. Both credit facilities contain two-year repayment periods for any amounts outstanding at the expiration of the revolving credit periods. At December 31, 1995 and 1994, short-term borrowings were $35 million and $60 million, respectively. The weighted average interest rates applied to such borrowings were 6.5 percent and 6.7 percent at December 31, 1995 and 1994, respectively.

H. Income Taxes

The annual federal corporate income tax returns have been audited by the Internal Revenue Service (IRS) for the tax years through 1989. The tax years 1990 through 1995 remain subject to IRS review. The Company does not believe that final settlement of the federal income tax returns for these years will have a materially adverse effect on its financial position or results of operations. The effects of the 1993 adoption of *SFAS No. 109* are discussed in "Income Taxes," Note A, on page 45. Implementation of the standard involved a change in accounting principle. The cumulative effect of $8 million on prior years was reported in 1993 as an increase in *net income*. The *SFAS No. 109* impact on 1993 *income before cumulative effect of changes in accounting principles* is immaterial.

Deferred Tax Liabilities

	1995	1994
	(Amounts in Thousands of Dollars)	
At December 31, deferred tax assets (liabilities) were:		
Investment tax credits unamortized	$ 48,033	$ 51,282
Gain on sale/leaseback of BV Unit 2	64,124	67,120
Tax benefit - long-term investments	214,089	61,667
Other	41,509	52,037
Deferred tax assets	367,755	232,106
Property depreciation	(871,539)	(880,342)
Regulatory asset	(172,008)	(183,175)
Loss on reacquired debt unamortized	(35,340)	(38,066)
Other	(90,499)	(100,471)
Deferred tax liabilities	(1,169,386)	(1,202,054)
Net Deferred Tax Liabilities	$ (801,631)	$ (969,948)

Income Taxes

		1995	1994	1993
		(Amounts in Thousands of Dollars)		
Currently payable:	Federal	$88,866	$ 70,908	$ 82,803
	State	29,915	33,407	36,755
Deferred - net:	Federal	(8,649)	(13,198)	(25,388)
	State	(5,640)	(72,662)	(8,342)
Investment tax credits deferred - net		(7,831)	(5,982)	(6,006)
Tax rate adjustment-regulatory tax receivable		—	80,500 (a)	—
Income Taxes		$96,661	$ 92,973	$ 79,822

(a) During 1994 the statutory Pennsylvania income tax rate was reduced from 12.25 percent to 9.99 percent. This resulted in a net decrease of $80.5 million in deferred tax liabilities and a corresponding reduction in the regulatory receivable.

Income Tax Expense Reconciliation

	1995	1994	1993
	(Amounts in Thousands of Dollars)		
Computed federal income tax at statutory rate	$95,591	$ 89,524	$ 80,558
Increase (decrease) in taxes resulting from:			
Tax audit settlement	—	—	(15,000)
State income taxes, net of federal income tax benefits	15,779	(25,516)	18,468
Amortization of deferred investment tax credits	(7,831)	(5,982)	(6,006)
Adjustment to regulatory receivable, net of federal tax	—	52,325	—
Revenue requirement adjustment to regulatory taxes	—	(12,178)	—
Other	(6,878)	(5,200)	1,802
Total Income Tax Expense	$96,661	$ 92,973	$ 79,822

Total income taxes differ from the amount computed by applying the statutory federal income tax rate to income before income taxes, before preferred and preference dividends of subsidiaries and before the cumulative effect of changes in accounting principles.

I. Leases

The Company leases nuclear fuel, a portion of a nuclear generating plant, certain office buildings, computer equipment and other property and equipment.

Capital Leases at December 31

	1995	1994
	(Amounts in Thousands of Dollars)	
Nuclear fuel	$112,573	$139,763
Electric plant	20,808	22,969
Total	133,381	162,732
Less accumulated amortization	(74,874)	(91,376)
Property Held Under Capital Leases – Net (a)	$ 58,507	$ 71,356

a) Includes $2,910 in 1995 and $3,201 in 1994 of capital leases with associated obligations retired.

In 1987, the Company sold and leased back its 13.74 percent interest in BV Unit 2; the sale was exclusive of transmission and common facilities. The total sales price of $537.9 million was the appraised value of the Company's interest in the property. The Company leased back its interest in the unit for a term of 29.5 years. The lease provides for semiannual payments and is accounted for as an operating lease. The Company is responsible under the terms of the lease for all costs of its interest in the unit. In December 1992, the Company participated in the refinancing of collateralized lease bonds to take advantage of lower interest rates and reduce the annual lease payments. The bonds were originally issued in 1987 for the purpose of partially financing the lease of BV Unit 2. In accordance with the BV Unit 2 lease agreement, the Company paid the premiums of approximately $36.4 million as a supplemental rent payment to the lessors. This amount was deferred and is being amortized over the remaining lease term. At December 31, 1995, the deferred balance was approximately $31.6 million.

Leased nuclear fuel is amortized as the fuel is burned. The amortization of all other leased property is based on rental payments made. Payments for capital and operating leases are charged to *operating expenses* on the statement of consolidated income.

Summary of Rental Payments

	1995	1994	1993
	(Amounts in Thousands of Dollars)		
Operating leases	$57,617	$56,437	$57,398
Amortization of capital leases	26,705	33,596	28,758
Interest on capital leases	4,332	4,996	5,382
Total Rental Payments	$88,654	$95,029	$91,538

Future Minimum Lease Payments

	Operating Leases	Capital Leases
Year Ended December 31,	*(Amounts in Thousands of Dollars)*	
1996	$ 58,095	$ 24,392
1997	57,870	13,862
1998	57,621	8,801
1999	57,206	5,130
2000	57,164	3,705
2001 and thereafter	902,097	20,946
Total Minimum Lease Payments	$1,190,053	76,836
Less amount representing interest		(21,239)
Present value of minimum lease payments for capital leases		$ 55,597 (a)

(a) Includes current obligations of $21.1 million at December 31, 1995.

Future minimum lease payments for capital leases are related principally to the estimated use of nuclear fuel financed through leasing arrangements and building leases. Minimum payments for operating leases are related principally to BV Unit 2 and certain of the corporate offices.

Future payments due to the Company, as of December 31, 1995, under subleases of certain corporate office space are approximately $4.4 million in 1996, $4.5 million in 1997 and $23.1 million thereafter.

J. Commitments and Contingencies

Construction

The Company estimates that it will spend, excluding the AFC and nuclear fuel, approximately $90 million, $90 million and $100 million on electric utility construction during 1996, 1997 and 1998, respectively. Approximately $5 million of capital expenditures for the reliability enhancements to the simple cycle units located at BI contemplated in the Company's petition before the PUC are excluded from these estimates. (See "Sale of Ft. Martin" discussion, Note E, on page 47.)

Nuclear-Related Matters

The Company operates two nuclear units and has an ownership interest in a third. The operation of a nuclear facility involves special risks, potential liabilities and specific regulatory and safety requirements. Specific information about risk management and potential liabilities is discussed below.

Nuclear Decommissioning. The PUC ruled that recovery of the decommissioning costs for Beaver Valley Unit 1 (BV Unit 1) could begin in 1977, and that recovery for BV Unit 2 and Perry Unit 1 could begin in 1988. The Company expects to decommission BV Unit 1, BV Unit 2 and Perry Unit 1 no earlier than the expiration of each plant's operating license, 2016, 2026 and 2025, respectively. BV Unit 1 will be placed in safe storage until the expiration of the BV Unit 2 operating license, at which time the units may be decommissioned together.

Based on site-specific studies finalized in 1992 for BV Unit 2, and in 1994 for BV Unit 1 and Perry Unit 1, the Company's share of the total estimated decommissioning costs, including removal and decontamination costs, currently being used to determine the Company's cost of service, are $122 million for BV Unit 1, $35 million for BV Unit 2, and $67 million for Perry Unit 1.

In conjunction with an August 18, 1994, PUC Accounting Order, the Company has increased the annual contribution to its decommissioning trusts by approximately $2 million to bring the total annual funding to approximately $4 million per year. In collaboration with the Company and several other Pennsylvania utilities, the PUC Office of Special Assistants is evaluating various decommissioning issues, including funding methods. The Company expects that any action relating to any forthcoming PUC report will result in further increases in annual contributions to its decommissioning trusts. Consistent with these anticipated future PUC actions, the Company's petition before the PUC for the sale of its ownership interest in the Ft. Martin Power Station provides for additional annual contributions to its nuclear decommissioning funds of $5 million for five years without any increase in existing electric utility rates. (See "Sale of Ft. Martin" discussion, Note E, on page 47.)

The Company records decommissioning costs under the category of *depreciation and amortization* expense and accrues a liability, equal to that amount for nuclear decommissioning expense. Such nuclear decommissioning funds are deposited in external, segregated trust accounts. The funds are invested in a portfolio of municipal bonds, certificates of deposit and United States government securities having a weighted average duration of four to seven years. Trust fund earnings increase the fund balance and the recorded liability. The market value of the aggregate trust fund balances at December 31, 1995, totaled approximately $28.5 million. On the Company's consolidated balance sheet, the decommissioning trusts have been reflected in *other long-term investments*, and the related liability has been recorded as *other non-current liabilities*.

Nuclear Insurance. All of the companies with an interest in BV Unit 1, BV Unit 2 and Perry Unit 1 maintain nuclear property insurance, which provides coverage for property damage, decommissioning, and decontamination liabilities. The Company's share of this program provides for $1.2 billion of insurance coverage for its net investment of $407.8 million in the Beaver Valley Power Station (BVPS) and $565.5 million in Perry Unit 1, plus its interest in BV Unit 2 with lease commitments of $405.2 million, at December 31, 1995. The lease commitments of $405.2 million represent the net present value of future lease payments discounted at 10.94 percent, the return currently authorized the Company by the PUC. The Company would be responsible for its share of any damages in excess of insurance coverage. In addition, if the property damage reserves of Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company, are inadequate to cover claims arising from an incident at any United States nuclear site covered by that insurer, the Company could be assessed retrospective premiums totaling a maximum of $10.9 million.

The *Price-Anderson Amendments* to the *Atomic Energy Act of 1954* limit public liability from a single incident at a nuclear plant to $8.9 billion. The Company has purchased $200 million of insurance, the maximum amount available, which provides the first level of financial protection.

Additional protection of $8.3 billion would be provided by an assessment of up to $75.5 million per incident on each nuclear unit in the United States. The Company's maximum total assessment, $56.6 million, which is based on its ownership or leasehold interests in three nuclear generating units, would be limited to a maximum of $7.5 million per incident per year. A further surcharge of 5 percent could be levied if the total amount of public claims exceeded the funds provided under the assessment program. Additionally, a state premium tax (typically 3 percent) could be charged on the assessment and surcharge. Finally, the United States Congress could impose other revenue-raising measures on the nuclear industry if funds prove insufficient to pay claims.

The Company carries extra expense insurance which would pay the incremental cost of any replacement power purchased (in addition to costs that would have been incurred had the units been operating) and other incidental expense after the occurrence of certain types of accidents at its nuclear units in a limited amount for a limited period of time. The coverage provides for 100 percent of the estimated extra expense per week during the 52-week period starting 21 weeks after an accident and 80 percent of such estimate per week for the following 104 weeks with no coverage thereafter. The amount and duration of actual extra expense could substantially exceed insurance coverage. NEIL also provides this insurance. If NEIL's reserves are inadequate to cover claims at any United States nuclear site covered by that insurer, the Company could be assessed retrospective premiums totaling a maximum of $3.5 million.

Beaver Valley Power Station Steam Generators. BVPS' units are equipped with steam generators designed and built by Westinghouse Electric Corporation (Westinghouse). Similar to other Westinghouse nuclear plants, stress corrosion cracking (SCC) has occurred in the steam generator tubes of BV Unit 1. BV Unit 2, which was placed in service eleven years after BV Unit 1, has not yet exhibited the degree of steam generator tube SCC experienced at BV Unit 1. It is, however, too early in the life of BV Unit 2 to determine the extent to which steam generator tube SCC may become a problem.

The Company has undertaken certain measures, such as increased inspections and tube plugging to minimize the operational impact and to reduce susceptibility to steam generator tube SCC. Although the Company has taken these steps to allay the effects of steam generator tube SCC, the inherent potential for future SCC in steam generator tubes of the Westinghouse design still exists. Material acceleration in SCC could lead to loss of plant efficiency, significant repairs or possible replacement of BV Unit 1's steam generators. Total replacement cost of BV Unit 1 steam generators is currently estimated at approximately $125 million. The Company would be responsible for $59 million of this total, which includes the cost of equipment removal and replacement, but excludes replacement power costs. The earliest that BV Unit 1's steam generators could be replaced is 1999.

The Company continues to explore all viable means of mitigating steam generator tube SCC, including new repair technologies. Both units will undergo 100 percent tube inspection during scheduled refueling outages in 1996. The Company will continue to monitor and evaluate the condition of the BVPS steam generators.

Spent Nuclear Fuel Disposal. The *Nuclear Waste Policy Act of 1982* established a policy for handling and disposing of spent nuclear fuel and a policy requiring the established final repository to accept spent fuel. Electric utility companies have entered into contracts with the DOE for the permanent disposal of spent nuclear fuel and high-level radioactive waste in compliance with this legislation. The DOE has indicated that its repository under these contracts will not be available for acceptance of spent fuel before 2010 at the earliest. Existing on-site spent fuel storage capacities at BV Unit 1, BV Unit 2 and Perry Unit 1 are expected to be sufficient until 2016, 2010 and 2011, respectively.

Uranium Enrichment Decontamination and Decommissioning Fund. Nuclear reactor licensees in the United States are assessed annually for the decontamination and decommissioning of DOE enrichment facilities. Assessments are based on the amount of uranium a utility had processed for enrichment prior to enactment of the *National Energy Policy Act of 1992* (NEPA) and are to be paid by such utilities over a 15-year period. At December 31, 1995, the Company's liability for contributions is approximately $9.9 million (subject to an inflation adjustment). Contributions, when made, are recovered from electric utility customers through the ECR.

Guarantees

The Company and the owners of Bruce Mansfield have guaranteed certain debt and lease obligations related to a coal supply contract for the Bruce Mansfield plant. At December 31, 1995, the Company's share of these guarantees was $25.4 million. The prices paid for the coal by the companies under this contract are expected to be sufficient to meet debt and lease obligations to be satisfied in the year 2000. (See "Deferred Coal Costs" discussion, Note F, on page 49.) The minimum future payments to be made by the Company solely in relation to these obligations are $6.2 million in 1996, $5.9 million in 1997, $5.6 million in 1998, $5.3 million in 1999 and

$4.2 million in 2000. The Company's total payments for coal purchased under the contract were $28.9 million in 1995, $23.3 million in 1994 and $26.5 million in 1993.

The Company has entered into various partnerships to enhance the credit associated with affordable housing investments made by third party investors. As part of the transactions, the Company has guaranteed a minimum defined yield and the funding of certain defined operating deficits in return for a fee. A portion of the fees received has been deferred to absorb any required payments with respect to these transactions. Based on an evaluation of the underlying housing projects, it is management's belief that such deferrals are ample for this purpose.

Residual Waste Management Regulations

In 1992, the Pennsylvania Department of Environmental Protection (DEP) issued Residual Waste Management Regulations governing the generation and management of non-hazardous residual waste, such as coal ash. The Company is assessing the sites which it utilizes and has developed compliance strategies under review by the DEP. Capital compliance costs of $3.0 million were incurred by the Company in 1995 to comply with these DEP regulations; on the basis of information currently available, an additional $2.5 million will be incurred in 1996. The expected additional capital cost of compliance through the year 2000 is estimated, based on current information, to be approximately $25 million. This estimate is subject to the results of ground water assessments and DEP final approval of compliance plans.

Other

The Company is involved in various other legal proceedings and environmental matters. The Company believes that such proceedings and matters, in total, will not have a materially adverse effect on its financial position or results of operations.

K. Long-Term Debt

The Company's 1947 first mortgage bond indenture was retired in the third quarter of 1995 following the maturity of the last bond series issued under the indenture. All of the Company's First Collateral Trust Bonds have been issued under a new mortgage indenture that was established in April 1992 (the 1992 Indenture). All First Collateral Trust Bonds became first mortgage bonds when the 1947 mortgage indenture was retired. The 1992 Indenture includes more flexible provisions and eliminates conventions such as mandatory sinking funds and formula-derived maintenance and replacement clauses.

The pollution control notes arise from the sale of bonds by public authorities for the purposes of financing construction of pollution control facilities at the Company's plants or refunding previously issued bonds. The Company is obligated to pay the principal and interest on these bonds. For certain of the pollution control notes, there is an annual commitment fee for an irrevocable letter of credit. Under certain circumstances, the letter of credit is available for the payment of interest on, or redemption of, all or a portion of the notes. In late 1994, pollution control notes totaling $114.1 million with an average interest rate of 10.34 percent were refinanced at lower adjustable interest rates.

Long-Term Debt at December 31

	Interest Rate	Maturity	*Principal Outstanding (Amounts in Thousands of Dollars)* 1995	1994
First Collateral Trust Bonds/ first mortgage bonds	4.75%-8.75%	1996-2025	$ 903,000 (a)	$ 950,400 (b)
Pollution control notes (c)	(d)	2003-2030	417,985	417,051
Sinking fund debentures	5%	2010	5,703	5,817
Term loans	6.49%	2000	65,000	—
Miscellaneous			13,462	8,833
Less unamortized debt discount and premium – net			(4,157)	(4,490)
Total Long-Term Debt			$1,400,993	$1,377,611

(a) Excludes $50.0 million in 1995 related to a current maturity on May 15, 1996.
(b) Excludes $9.6 million in 1994 related to sinking fund requirements on the underlying first mortgage bonds and $49.0 million related to the maturity on June 1, 1995, of the last first mortgage bonds issued under the 1947 indenture.
(c) Excludes $0.9 million in 1994 related to sinking fund requirements on the underlying first mortgage bonds.
(d) The pollution control notes have adjustable interest rates. The interest rates at year-end averaged 3.9 percent in 1995 and 4.3 percent in 1994.

At December 31, 1995, sinking fund requirements (related solely to the sinking fund debentures) and maturities of long-term debt outstanding for the next five years were: $50.4 million in 1996; $50.7 million in 1997, $75.7 million in 1998, $75.8 million in 1999 and $165.8 million in 2000.

Total interest costs incurred were $107.7 million in 1995, $110.7 million in 1994 and $118.1 million in 1993. Interest costs attributable to long-term debt and other interest were $102.4 million, $105.1 million and $112.0 million in 1995, 1994 and 1993, respectively. Interest costs incurred also include $5.3 million, $5.6 million and $6.1 million attributable to capital leases in 1995, 1994 and 1993, respectively. Of these amounts, $1.8 million in 1995, $2.0 million in 1994 and $2.0 million in 1993 were capitalized as AFC. Debt discount or premium and related issuance expenses are amortized over the lives of the applicable issues.

During 1994, the Company's BV Unit 2 lease arrangement was amended to reflect an increase in federal income tax rates. At the same time, the associated letter of credit securing the lessor's equity interest in the unit was increased from $188 million to $194 million and the term of the letter of credit was extended to 1999. If certain specified events occur, the letter of credit could be drawn down by the owners, the leases could terminate and collateralized lease bonds ($409 million at December 31, 1995) would become direct obligations of the Company.

At December 31, 1995 and 1994, the Company was in compliance with all of its debt covenants.

At December 31, 1995, the fair value of the Company's long-term debt, including current maturities and sinking fund requirements, estimated on the basis of quoted market prices for the same or similar issues or current rates offered to the Company for debt of the same remaining maturities, was $1,466.4 million. The principal amount included in the Company's consolidated balance sheet is $1,441.7 million.

L. Preferred and Preference Stock of Subsidiaries

Preferred and Preference Stock of Subsidiaries at December 31

		(Shares and Amounts in Thousands)					
		1995		1994		1993	
	Call Price Per Share	Shares	Amount	Shares	Amount	Shares	Amount
Preferred Stock Series:							
3.75% (a) (b) (c)	$51.00	148	$ 7,407	148	$ 7,407	148	$ 7,407
4.00% (a) (b) (c)	51.50	550	27,486	550	27,486	550	27,486
4.10% (a) (b) (c)	51.75	120	6,012	120	6,012	120	6,012
4.15% (a) (b) (c)	51.73	132	6,643	132	6,643	132	6,643
4.20% (a) (b) (c)	51.71	100	5,021	100	5,021	100	5,021
$2.10 (a) (b) (c)	51.84	159	8,039	159	8,039	159	8,039
$7.20 (a) (c) (d)	—	—	—	298	29,732	319	31,915
9.00% (e)	—	—	3,000	—	—	—	—
Total Preferred Stock		1,209	63,608	1,507	90,340	1,528	92,523
Preference Stock Series: (f)							
$2.10 (c) (g)	—	—	—	—	—	1,175	29,383
$7.50 (d) (h)	—	—	—	—	—	84	8,392
Plan Series A (c) (i)	37.18	834	29,615	841	29,857	844	29,956
Total Preference Stock		834	29,615	841	29,857	2,103	67,731
Deferred ESOP benefit			(22,257)		(24,852)		(27,126)
Total Preferred and Preference Stock			$70,966		$95,345		$133,128

(a) Preferred stock: 4,000,000 authorized shares; $50 par value; cumulative
(b) $50 per share involuntary liquidation value
(c) Non-redeemable
(d) $100 per share involuntary liquidation value
(e) 500 authorized shares; 10 issued $300,000 par value; involuntary liquidation value $300,000 per share; redeemable beginning August 2000
(f) Preference stock: 8,000,000 authorized shares; $1 par value; cumulative
(g) $25 per share involuntary liquidation value
(h) Redeemable
(i) $35.50 per share involuntary liquidation value

Holders of Duquesne's preferred stock are entitled to cumulative quarterly dividends. If four quarterly dividends on any series of preferred stock are in arrears, holders of the preferred stock are entitled to elect a majority of Duquesne's board of directors until all dividends have been paid. At December 31, 1995, Duquesne had made all preferred stock dividend payments.

Holders of Duquesne's preference stock are entitled to receive cumulative quarterly dividends if dividends on all series of preferred stock are paid. If six quarterly dividends on any series of preference stock are in arrears, holders of the preference stock are entitled to elect two of Duquesne's directors until all dividends have been paid. At December 31, 1995, the Company had made all dividend payments. Preferred and preference dividends of subsidiaries included in *Interest and Other Charges* were $5.9 million, $6.0 million and $8.9 million in 1995, 1994 and 1993, respectively.

In December 1991, the Company established an Employee Stock Ownership Plan (ESOP) to provide matching contributions for a 401(k) Retirement Savings Plan for Management Employees. (See "Employee Benefits," Note N, on page 57.) The Company issued and sold 845,070 shares of *preference stock, plan series A* to the trustee of the ESOP. As consideration for the stock, the Company received a note valued at $30 million from the trustee. The preference stock has an annual dividend rate of $2.80 per share, and each share of the preference stock is exchangeable for one and one half shares of DQE common stock. At December 31, 1995, $22.3 million of preference stock issued in connection with the establishment of the ESOP had been offset, for financial statement purposes, by the recognition of a deferred ESOP benefit. Dividends on the preference stock and cash contributions from the Company are used to repay the ESOP note. The Company made cash contributions of approximately $2.1 million for 1995, $2.3 million for 1994 and $2.1 million for 1993. These cash contributions were the difference between the ESOP debt service and the amount of dividends on ESOP shares (approximately $2.3 million in 1995, $2.4 million in 1994 and $2.3 million in 1993). As shares of preference stock are allocated to the accounts of participants in the ESOP, the Company recognizes compensation expense, and the amount of the deferred compensation benefit is amortized. The Company recognized compensation expense related to the 401(k) plans of $2.3 million in 1995, $1.8 million in 1994 and $1.7 million in 1993.

Outstanding *preferred and preference stock* is generally callable, on notice of not less than thirty days, at stated prices plus accrued dividends. On September 1, 1995, Duquesne called for redemption of all of its outstanding shares of $7.20 preferred stock. On January 14, 1994, Duquesne called for redemption all of its outstanding shares of $2.10 and $7.50 preference stock. None of the remaining Duquesne preferred or preference stock issues has mandatory purchase requirements.

M. Common Stock

Changes in the Number of Shares of DQE Common Stock Outstanding

	1995	1994	1993
	(Amounts in Thousands of Shares)		
Outstanding as of January 1	78,459	79,518	79,425
Reissuance from *treasury stock*	83	116	93
Repurchase of *common stock*	(986)	(1,175)	—
Outstanding as of December 31	77,556	78,459	79,518

On April 19, 1995, the Company's board of directors declared a three-for-two stock split for shareholders of record on May 1, 1995. One additional share of *common stock* was issued for every two shares outstanding as of the record date. All references in the consolidated financial statements as to issued and outstanding shares and per share amounts have been restated to reflect the stock split.

The Company has continuously paid dividends on common stock since 1953. The quarterly dividend declared in the fourth quarter of 1995 on the post-split shares was increased from $.30 to $.32 per share. The Company has increased its annual dividend for each of the last eight years. The Company's annualized dividend per share was $1.28, $1.17 and $1.12 in 1995, 1994 and 1993, respectively.

An amendment to the *Restated Articles of DQE* changing the Company's *common stock* from stock with a par value of $1.00 per share to stock having no par value, was approved by shareholders at the Company's Annual Meeting of Shareholders on April 20, 1994.

Dividends may be paid on the Company's *common stock* to the extent permitted by law and as declared by the board of directors. However, payments of dividends on Duquesne's common stock may be restricted by Duquesne's obligations to holders of preferred and preference stock pursuant to Duquesne's *Restated Articles* of incorporation. No dividends or distributions may be made on Duquesne's common stock if Duquesne has not paid dividends or sinking fund obligations on its preferred or preference stock. Further, the aggregate amount of Duquesne's common stock dividend payments or distributions may not exceed certain percentages of *net income* if the ratio of *common shareholders' equity* to *total capitalization* is less than specified percentages. As all of Duquesne's common stock is owned by the Company, to the extent that Duquesne cannot pay common dividends, the Company may not be able to pay dividends to its common shareholders. No part of the *retained earnings* of the Company was restricted at December 31, 1995.

N. Employee Benefits

Retirement Plans

The Company maintains retirement plans to provide pensions for all full-time employees. Upon retirement, an employee receives a monthly pension based on his or her length of service and compensation. The cost of funding the pension plan is determined by the unit credit actuarial cost method. The Company's policy is to record this cost as an expense and to fund the pension plans by an amount that is at least equal to the minimum funding requirements of the *Emple~ee Retirement Income Security Act of 1974 (ERISA)* but not to exceed the maximum tax dedu~ble amount for the year. Pension costs charged to expense or construction were $6.1 million for 1995, $8.9 million for 1994 and $9.8 million for 1993.

Funded Status of the Retirement Plans and Amounts Recognized on the Consolidated Balance Sheet at December 31

	1995	1994
	(Amounts in Thousands of Dollars)	
Actuarial present value of benefits rendered to date:		
Vested benefits	$378,344	$314,933
Non-vested benefits	19,110	17,282
Accumulated benefits obligations based on compensation to date	397,454	332,215
Additional benefits based on estimated future salary levels	53,757	59,318
Projected benefits obligation	451,211	391,533
Fair market value of plan assets	490,870	412,724
Projected benefits obligation under plan assets	$ 39,659	$ 21,191
Unrecognized net gain	$124,794	$ 95,691
Unrecognized prior service cost	(37,535)	(30,365)
Unrecognized net transition liability	(15,665)	(17,477)
Net pension liability per consolidated balance sheet	(31,935)	(26,658)
Total	$ 39,659	$ 21,191
Assumed rate of return on plan assets	8.00%	8.00%
Discount rate used to determine projected benefits obligation	7.00%	8.00%
Assumed change in compensation levels	5.00%	5.50%

Pension assets consist primarily of common stocks, United States obligations and corporate debt securities.

Components of Net Pension Cost

	1995	1994	1993
		(Amounts in Thousands of Dollars)	
Service cost (benefits earned during the year)	$ 9,953	$ 12,482	$ 11,657
Interest on projected benefits obligation	30,063	28,221	27,423
Return on plan assets	(99,246)	1,967	(41,725)
Net amortization and deferrals	65,316	(33,783)	12,454
Net Pension Cost	$ 6,086	$ 8,887	$ 9,809

Retirement Savings Plan and Other Benefit Options

The Company sponsors separate 401(k) retirement plans for its management and bargaining unit employees.

The 401(k) Retirement Savings Plan for Management Employees provides that the Company will match employee contributions to a 401(k) account up to a maximum of six percent of an employee's eligible salary. The Company match consists of a $.25 base match per eligible contribution dollar and an additional $.25 incentive match per eligible contribution dollar, if Board-approved targets are achieved. The 1995 incentive target for management was accomplished. The Company is funding its matching contributions to the 401(k) Retirement Savings Plan for Management Employees with payments to an ESOP established in December 1991. (See "Preferred and Preference Stock of Subsidiaries," Note L, on page 55.)

The 401(k) Retirement Savings Plan for IBEW Represented Employees provides that beginning in 1995, the Company will match employee contributions to a 401(k) account up to a maximum of four percent of an employee's eligible salary. The Company match consists of a \$.25 base match per eligible contribution dollar and an additional \$.25 incentive match per eligible contribution dollar, if certain non-occupational illness and injury targets are met. In 1995, these incentive targets were not met by the Company's union-represented employees.

The Company's shareholders have approved a long-term incentive plan through which the Company may grant management employees options to purchase, during the years 1987 through 2003, up to a total of 6.9 million shares of the Company's *common stock* at prices equal to the fair market value of such stock on the dates the options were granted. At December 31, 1995, approximately 2.6 million of these shares were available for future grants.

The following information is restated to reflect the 1995 stock split. As of December 31, 1995, 1994 and 1993, respectively, active grants totaled 2,159,000; 2,118,000; and 1,763,000 shares. Exercise prices of these options ranged from \$8.2084 to \$27.625 at December 31, 1995, and from \$8.2084 to \$23.0833 at December 31, 1994 and December 31, 1993. Expiration dates of these grants ranged from 1997 to 2005 at December 31, 1995; from 1997 to 2004 at December 31, 1994; and from 1997 to 2003 at December 31, 1993. As of December 31, 1995, 1994 and 1993, respectively, stock appreciation rights (SARs) had been granted in connection with 1,202,000; 1,190,000 and 1,193,000 of the options outstanding. During 1995, 367,000 SARs were exercised; 133,000 options were exercised at prices ranging from \$8.2084 to \$21.6667 and 28,000 options were cancelled. During 1994, 1,254,000 SARs were exercised; 339,000 options were exercised at prices ranging from \$8.2084 to \$18.9167; and 80,000 options were cancelled. During 1993, 1,122,000 SARs were exercised; 227,000 options were exercised at prices ranging from \$8.2084 to \$18.9167; and 78,000 options were cancelled. Of the active grants at December 31, 1995, 1994 and 1993, respectively, 929,000; 918,000; and 867,000 were not exercisable.

Other Postretirement Benefits

In addition to pension benefits, the Company provides certain health care benefits and life insurance for some retired employees. Substantially all of the Company's full-time employees may, upon attaining the age of 55 and meeting certain service requirements, become eligible for the same benefits available to retired employees. Participating retirees make contributions, which are adjusted annually, to the health care plan. The life insurance plan is non-contributory. Company-provided health care benefits terminate when covered individuals become eligible for Medicare benefits or reach age 65, whichever comes first. The Company funds actual expenditures for obligations under the plans on a "pay-as-you-go" basis. The Company has the right to modify or terminate the plans.

As of January 1, 1993, the Company adopted *Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions*, which requires the actuarially determined costs of the aforementioned postretirement benefits to be accrued over the period from the date of hire until the date the employee becomes fully eligible for benefits. The Company has adopted this standard prospectively and has elected to amortize the transition liability over 20 years.

Components of Postretirement Cost

	1995	1994
	(Amounts in Thousands of Dollars)	
Service cost (benefits earned during the period)	\$1,315	\$1,631
Interest cost on accumulated benefit obligation	2,340	2,294
Amortization of the transition obligation over twenty years	1,700	1,700
Other	(582)	—
Total Postretirement Cost	\$4,773	\$5,625

The accumulated postretirement benefit obligation comprises the present value of the estimated future benefits payable to current retirees and a pro rata portion of estimated benefits payable to active employees after retirement.

Funded Status of Postretirement Plan and Amounts Recognized on the Consolidated Balance Sheet at December 31

	1995	1994
	(Amounts in Thousands of Dollars)	
Actuarial present value of benefits:		
Retirees	$ 7,359	$ 6,292
Fully eligible active plan participants	3,187	3,074
Other active plan participants	21,935	20,543
Accumulated postretirement benefit obligation	32,481	29,909
Fair market value of plan assets	—	—
Accumulated benefit obligation in excess of plan assets	$(32,481)	$(29,909)
Unrecognized net actuarial gains	$ 8,427	$ 9,481
Unrecognized net transition liability	(28,898)	(30,598)
Postretirement liability per consolidated balance sheet	(12,010)	(8,792)
Total	$(32,481)	$(29,909)
Discount rate used to determine projected benefit obligation	7.00%	8.00%
Health care cost trend rates:		
For year beginning January 1	8.80%	8.60%
Ultimate rate	5.50%	6.50%
Year ultimate rate is reached	2000	1999
Effect of a one percent increase in health care cost trend rates:		
On accumulated projected benefit obligation	$ 3,228	$ 3,137
On aggregate of annual service and interest costs	$ 435	$ 465

O. Quarterly Financial Information (Unaudited)

Summary of Selected Quarterly Financial Data (Thousands of Dollars, Except Per Share Amounts)

[The quarterly data reflect seasonal weather variations in the Company's service territory.]

1995	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues (a)	$298,277	$283,372	$347,265	$291,248
Operating Income (a)	80,607	66,870	105,528	69,460
Net Income	40,901	35,685	55,269	38,708
Earnings Per Share (b)	.52	.46	.72	.50
Stock Price: (b)				
High	22⅜	25	26⅝	30¾
Low	19⅝	21⅝	23½	26½
1994				
Operating Revenues (a)	$307,270	$295,409	$333,256	$287,975
Operating Income (a)	84,045	65,667	101,945	65,210
Net Income	37,296	33,029	48,592	37,899
Earnings Per Share (b)	.47	.42	.61	.48
Stock Price: (b)				
High	23	21⅞	20⅝	20⅛
Low	20½	19⅛	18⅜	18½

(a) Restated to conform with presentations adopted during 1995.
(b) Earnings per share and stock prices have been restated to reflect the stock split.

DQE Officers

Wesley W. von Schack, 51. *Chairman of the Board, President and Chief Executive Officer.* Joined the company in 1984. Previously held senior executive positions in finance and administration with other utility and communications companies. Directorships included in listing on page 20.

Gary L. Schwass, 50. *Executive Vice President, Chief Financial Officer and Treasurer.* Previously served in a variety of senior executive positions in finance and management with Consumers Power Company. Joined the company in 1985. Directorships include Chairman, Western Pennsylvania Development Credit Corporation (promotes small business through lending activities), and Vice President and Treasurer, Holy Family Foundation (supports families in crisis).

David D. Marshall, 43. *Executive Vice President.* Previously held senior executive positions in finance at Central Vermont Public Service. Joined the company in 1985. Directorships included on page 20.

James D. Mitchell, 44. *Vice President.* Previously held senior financial positions with Duquesne Light and U.S. West, Inc. Joined the company in 1988. Directorships include Three Rivers Youth (helps troubled teenagers).

Victor A. Roque, 49. *Vice President and General Counsel.* Formerly Vice President, General Counsel and Secretary for Orange and Rockland Utilities. Joined the company in 1994. Directorships include the Pennsylvania Chamber of Business and Industry (economic development) and the United Way Good Neighbors Advisory Committee. Also a member of the Salvation Army Greater Pittsburgh Advisory Board.

Diane S. Eismont, 51
Secretary

Morgan K. O'Brien, 35
Controller

Donald J. Clayton, 41
Assistant Treasurer

Jack Saxer, Jr., 52
Assistant Treasurer

Joan S. Senchyshyn, 57
Assistant Secretary

Duquesne Light Company

Wesley W. von Schack, 51
Chairman of the Board and Chief Executive Officer

David D. Marshall, 43
President and Chief Operating Officer

Gary L. Schwass, 50
Senior Vice President and Chief Financial Officer

James E. Cross, 49
Senior Vice President, Nuclear

Dianna L. Green, 49
Senior Vice President, Customer Operations

Roger D. Beck, 59
Vice President, Customer Services

Gary R. Brandenberger, 58
Vice President, Power Supply

William J. DeLeo, 45
Vice President, Marketing and Corporate Performance

Victor A. Roque, 49
Vice President and General Counsel

Donald J. Clayton, 41
Treasurer

Diane S. Eismont, 51
Secretary

Morgan K. O'Brien, 35
Controller

Jack Saxer, Jr., 52
Assistant Vice President, Administration

Sally K. Wade, 42
Assistant Vice President, Human Resources

William F. Fields, 45
Assistant Treasurer

Joan S. Senchyshyn, 57
Assistant Secretary

Duquesne Enterprises

Thomas A. Hurkmans, 30
President

Anthony J. Villiotti, 49
Vice President, Treasurer and Controller

Montauk

James D. Mitchell, 44
President

Donald J. Clayton, 41
Vice President

Lydia E. York, 36
Vice President

William F. Fields, 45
Treasurer

James E. Wilson, 30
Controller

DQE Energy Services

Alexis Tsaggaris, 47
President

John W. Welch, 44
Executive Vice President

John J. Drozdowski, 40
Treasurer and Controller

Shareholder Reference Guide

Common Stock
Trading Symbol: DQE
Stock Exchanges Listed and Traded:
New York, Philadelphia, Chicago
Number of Common Shareholders of Record at Year-End: 79,048.

Annual Meeting
Shareholders are cordially invited to attend our Annual Meeting of Shareholders at 10 a.m., April 23, at the Smith Barney Plaza, 388 Greenwich St., New York, NY 10013.

DQE Internet Home Page
A variety of shareholder and customer information is available on DQE's home page on the World Wide Web. Our address is http://www.dqe.com. The site is best viewed using the latest version of Netscape software.

ELECTRI STOCK

The following investor services are available through DQE's dividend reinvestment and stock purchase plan.

Direct Purchase of DQE Stock
DQE offers non-shareholders the ability to purchase stock directly through the company. Call or write for a prospectus on this popular program.

Automatic Cash Contributions
Through this program, current reinvestment plan participants can make regular cash contributions to purchase additional shares of DQE common stock by having funds automatically withdrawn from their bank accounts.

Other Features and Services

- Purchase and sale of plan shares at nominal commissions.
- Acceptance of certificates for safekeeping.
- Reregistration of some or all of a shareholder's holdings.
- Creation of new accounts as gifts for family and friends.

Shareholder Services/Assistance
By telephone, representatives are available from 7:30 a.m. to 4:30 p.m. (Eastern time) to assist you with the following services:

Direct purchase of initial shares
Direct deposit of dividends
Automatic cash contributions
Dividend reinvestment
Stock transfer
Unreceived dividend payment
Change of address
Lost stock certificate

Stock Certificate Transfers
Shareholders with only stock certificates to transfer should send their certificates and the related documents to our transfer agent:

Boston Equi-Serve
Transfer Processing
150 Royall Street 45-01-05
Canton, MA 02021

Direct Deposit
Your DQE quarterly dividends can be deposited automatically into a personal checking or savings account. Call Shareholder Relations toll-free for more information.

Financial Community Inquiries
Analysts, investment managers and brokers should direct their inquiries to 1-412-393-4133; FAX 1-412-393-6571. Written inquiries should be sent to the Investor Relations Department at the address below.

Dividend Tax Status
The company estimates that all of the common stock dividends paid in 1995 are taxable as dividend income. This estimate is subject to audit by the Internal Revenue Service.

Form 10-K
If you hold or are a beneficial holder of DQE common stock as of February 21, 1996, the record date for the 1996 Annual Meeting, we will send you, free upon request, a copy of DQE's Annual Report or Form 10-K as filed with the Securities and Exchange Commission for 1995. Requests must be made in writing to the Secretary, DQE, at the address listed below.

Reg. U.S. Pat. & Tm. Off.

DQE and its affiliated companies are Equal Opportunity Employers.

DQE
Shareholder Relations
Box 68
Pittsburgh, PA 15230-0068

Toll-free: 1-800-247-0400
In Pittsburgh: 393-6167
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DQE

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