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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application for Authority to Transfer the Facilities of VILLAGE WATER, LTD. and Certificate Nos. 585-W and 503-S in Polk County, Florida to AQUASOURCE UTILITY, INC.	Docket No. 981697-WS

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RECORDS AND REPORTING

NOTICE OF FILING

Applicant hereby notices the filing of the Financial Statement of DQE, Inc. in the above-referenced docket pursuant to Rule 25-30.037(3)(g), Florida Administrative Code.

Respectfully submitted on this 10th day of December, 1998, by:

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Statement of Consolidated Income

		(Thousands of Dollars, Except Per Share Amounts) Year Ended December 31,		
		1997	1996	1995
Operating Revenues	Sales of Electricity:			
	Residential	**$ 405,915**	$ 405,392	$ 414,291
	Commercial	**494,834**	489,646	491,789
	Industrial	**198,708**	190,723	190,689
	Provision for doubtful accounts	**(11,000)**	(10,582)	(13,430)
	Net customer revenues	**1,088,457**	1,075,179	1,083,339
	Utilities	**24,861**	58,292	55,963
	Total Sales of Electricity	**1,113,318**	1,133,471	1,139,302
	Other	**105,856**	92,724	80,860
	Total Operating Revenues	**1,219,174**	1,226,195	1,220,162
Operating Expenses	Fuel and purchased power	**223,411**	236,924	231,968
	Other operating	**306,747**	298,977	292,997
	Maintenance	**82,869**	78,386	81,516
	Depreciation and amortization	**242,843**	222,928	202,558
	Taxes other than income taxes	**82,567**	85,974	88,658
	Total Operating Expenses	**938,437**	923,189	897,697
Operating Income	**Operating Income**	**280,737**	303,006	322,465
Other Income	Long-term investment income	**64,464**	49,636	28,975
	Gain on dispositions	**34,364**	5,119	9,129
	Interest and other income	**30,979**	19,035	14,210
	Total Other Income	**129,807**	73,790	52,314
	Interest and Other Charges	**115,638**	110,270	107,555
	Income Before Income Taxes	**294,906**	266,526	267,224
	Income Taxes	**95,805**	87,388	96,661
Net Income	**Net Income**	**$ 199,101**	$ 179,138	$ 170,563
	Average Number of Common Shares Outstanding (Thousands of Shares)	**77,492**	77,349	77,674
Earnings Per Share	**Basic Earnings Per Share of Common Stock**	**$2.57**	$2.32	$2.20
	Diluted Earnings Per Share of Common Stock	**$2.54**	$2.29	$2.17
Dividends Declared	**Dividends Declared Per Share of Common Stock**	**$1.38**	$1.30	$1.21

See notes to consolidated financial statements.

Statement of Consolidated Retained Earnings

	(Thousands of Dollars) As of December 31,		
	1997	1996	1995
Balance at beginning of year	**$ 777,607**	$ 698,986	$ 622,072
Net income	**199,101**	179,138	170,563
Dividends declared	**(106,959)**	(100,517)	(93,649)
Balance at end of year	**$ 869,749**	$ 777,607	$ 698,986

See notes to consolidated financial statements.

Consolidated Balance Sheet

Assets

	(Thousands of Dollars) As of December 31, 1997	1996
Current Assets:		
Cash and temporary cash investments	$ 356,412	$ 410,978
Receivables:		
Electric customer accounts receivable	90,149	92,475
Other utility receivables	23,106	22,402
Other receivables	33,472	33,936
Less: Allowance for uncollectible accounts	(15,016)	(18,688)
Total Receivables – Net	131,711	130,125
Materials and supplies (at average cost):		
Coal	20,418	19,097
Operating and construction	53,088	52,669
Total Materials and Supplies	73,506	71,766
Other current assets	7,727	9,359
Total Current Assets	569,356	622,228
Long-Term Investments:		
Leveraged leases	349,129	134,133
Affordable housing	137,860	150,270
Gas reserves	92,645	79,916
Other leases	69,329	85,893
Other	73,823	68,477
Total Long-Term Investments	722,786	518,689
Property, Plant and Equipment:		
Electric plant in service	4,335,149	4,275,110
Construction work in progress	56,471	45,059
Property held under capital leases	113,662	99,608
Property held for future use	3,980	190,821
Other	115,866	176,872
Gross property, plant and equipment	4,625,128	4,787,470
Less: Accumulated depreciation and amortization	(1,962,794)	(1,969,945)
Total Property, Plant and Equipment – Net	2,662,334	2,817,525
Other Non-Current Assets:		
Regulatory assets	680,885	636,816
Other	59,041	43,734
Total Other Non-Current Assets	739,926	680,550
Total Assets	$4,694,402	$4,638,992

See notes to consolidated financial statements.

Liabilities and Capitalization

	(Thousands of Dollars) As of December 31, 1997	1996
Current Liabilities:		
Notes payable	$ —	$ 749
Current maturities and sinking fund requirements	**97,844**	72,831
Accounts payable	**85,085**	96,230
Accrued liabilities	**54,386**	58,044
Dividends declared	**30,312**	28,633
Other	**14,339**	4,075
Total Current Liabilities	**281,966**	260,562
Non-Current Liabilities:		
Deferred income taxes – net	**693,215**	759,089
Deferred income	**225,107**	189,293
Deferred investment tax credits	**97,782**	106,201
Capital lease obligations	**37,540**	28,407
Other	**255,467**	240,763
Total Non-Current Liabilities	**1,309,111**	1,323,753
Commitments and Contingencies (Notes B through M)		
Capitalization:		
Long-Term Debt	**1,376,121**	1,439,746
Preferred and Preference Stock of Subsidiaries:		
Non-redeemable preferred stock	**216,156**	213,608
Non-redeemable preference stock	**28,295**	28,997
Total preferred and preference stock before deferred employee stock ownership plan (ESOP) benefit	**244,451**	242,605
Deferred ESOP benefit	**(16,400)**	(19,533)
Total Preferred and Preference Stock of Subsidiaries	**228,051**	223,072
Common Shareholders' Equity:		
Common stock – no par value (authorized – 187,500,000 shares; issued – 109,679,154 shares)	**1,001,225**	990,502
Retained earnings	**869,749**	777,607
Treasury stock (at cost) (31,998,723 and 32,406,135 shares)	**(371,821)**	(376,250)
Total Common Shareholders' Equity	**1,499,153**	1,391,859
Total Capitalization	**3,103,325**	3,054,677
Total Liabilities and Capitalization	**$4,694,402**	$4,638,992

See notes to consolidated financial statements.

Statement of Consolidated Cash Flows

		(Thousands of Dollars)		
		Year Ended December 31,		
		1997	1996	1995
Cash Flows from Operating Activities	Net income	**$199,101**	$179,138	$170,563
	Principal non-cash charges (credits) to net income:			
	Depreciation and amortization	**242,843**	222,928	202,558
	Capital lease, nuclear fuel and investment amortization	**67,671**	53,166	38,847
	Deferred income taxes and investment tax credits – net	**60,811**	(43,170)	(10,921)
	Gain on disposition of investments	**(34,364)**	(5,119)	(9,129)
	Investment income	**(66,246)**	(57,429)	(31,054)
	Changes in working capital other than cash	**(37,229)**	2,915	34,875
	(Increase) decrease in ECR	**(25,318)**	(3,948)	11,652
	Other	**(40,038)**	34,445	48,731
	Net Cash Provided from Operating Activities	**367,231**	382,926	456,122
Cash Flows from Investing Activities	Long-term investments	**(219,122)**	(77,147)	(191,719)
	Capital expenditures	**(118,338)**	(101,150)	(94,164)
	Proceeds from disposition of investments	**86,300**	18,100	1,929
	Sale of generating station	—	169,100	—
	Payment for purchase of GSF Energy, net of cash acquired	—	(24,234)	—
	Other	**(4,938)**	(1,898)	(3,854)
	Net Cash Used in Investing Activities	**(256,098)**	(17,229)	(287,808)
Cash Flows from Financing Activities	Dividends on common stock	**(106,959)**	(100,517)	(93,649)
	Reductions of long-term obligations:			
	Long-term debt	**(52,100)**	(50,812)	(56,114)
	Capital leases	**(13,551)**	(19,326)	(26,373)
	Preferred and preference stock	—	—	(29,732)
	Repurchase of common stock	**(30)**	(11,717)	(21,271)
	Issuance of preferred stock	—	150,000	—
	Issuance of long-term debt	—	85,000	65,000
	Decrease in notes payable	—	(28,637)	(20,236)
	Other	**6,941**	(3,477)	(11,230)
	Net Cash (Used in) Provided from Financing Activities	**(165,699)**	20,514	(193,605)
	Net (decrease) increase in cash and temporary cash investments	**(54,566)**	386,211	(25,291)
	Cash and temporary cash investments at beginning of year	**410,978**	24,767	50,058
	Cash and temporary cash investments at end of year	**$356,412**	$410,978	$ 24,767

Supplemental Cash Flow Information

Cash Paid During the Year	Interest (net of amount capitalized)	**$ 95,413**	$ 95,702	$ 99,954
	Income taxes	**$ 66,703**	$ 91,641	$ 82,884
Non-Cash Investing and Financing Activities	Capital lease obligations recorded	**$ 27,514**	$ 13,050	$ 14,961
	Equity funding obligations recorded	**$ 5,441**	$ 36,716	$ 21,827
	Equity funding obligations cancelled	**$ 9,107**	$ —	$ —
	Preferred stock issued in conjunction with long-term investments	**$ 2,548**	$ —	$ 3,000

On May 1, 1997, DQE exchanged its shares in Chester Engineers for shares of common stock of the purchaser of Chester Engineers, which were subsequently sold at various dates through June 5, 1997.

See notes to consolidated financial statements.

Notes to Consolidated Financial Statements

A. Summary of Significant Accounting Policies

Consolidation and Proposed Merger

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

Duquesne is an electric utility engaged in the generation, transmission, distribution and sale of electric energy and is the largest of DQE's subsidiaries. DE makes strategic investments beneficial to DQE's core energy business. These investments are intended to enhance DQE's capabilities as an energy provider, increase asset utilization, and act as a hedge against changing business conditions. DES is a diversified energy services company offering a wide range of energy solutions for industrial, utility and consumer markets worldwide. DES initiatives include energy facility development and operation, domestic and international independent power production, and the production and supply of innovative fuels. DQEnergy was formed to align DQE with strategic partners to capitalize on opportunities in the energy services industry. These alliances are intended to enhance the utilization and value of DQE's strategic investments and capabilities while establishing DQE as a total energy provider. Montauk is a financial services company that makes long-term investments and provides financing for the Company's other market-driven businesses and their customers.

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

On August 7, 1997, the shareholders of the Company and Allegheny Energy, Inc. (AYE), approved a proposed tax-free, stock-for-stock merger. Upon consummation of the merger, DQE will be a wholly owned subsidiary of AYE. Immediately following the merger, Duquesne, DE, DES, DQEnergy and Montauk will remain wholly owned subsidiaries of DQE. The transaction is intended to be accounted for as a pooling of interests. Under the pooling of interests method of accounting for a business combination, the recorded assets, liabilities and equity of each of the combining companies are carried forward to the combined corporation at their recorded amounts. Accordingly, no goodwill, including the related future earnings impact of goodwill amortization, results from a transaction accounted for as a pooling of interests. In order to qualify for pooling treatment, many requirements must be met by each of the combining companies for a period of time before and after the combination occurs. Examples of the requirements prior to the merger include limitations on: dividends paid on common stock, stock repurchases, stock compensation plan activity and sales of significant assets. Management has focused and will continue to focus on meeting the pooling requirements as they relate to the Company prior to the merger.

Under the terms of the transaction, the Company's shareholders will receive 1.12 shares of AYE common stock for each share of the Company's common stock and AYE's dividend in effect at the time of the closing of the merger. The transaction is expected to close in mid-1998, subject to approval of applicable regulatory agencies, including the public utility commissions in Pennsylvania and Maryland, the Securities and Exchange Commission (SEC), the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC).

In September 1997, the City of Pittsburgh filed a federal antitrust suit seeking to prevent the merger and asking for monetary damages. Although the United States District Court for the District of Western Pennsylvania dismissed the suit in January 1998, the City of Pittsburgh filed an appeal and asked for expedited review. A hearing is currently scheduled for late March 1998. Unless otherwise indicated, all information presented in this Annual Report relates to the Company only and does not take into account the proposed merger between the Company and AYE.

Basis of Accounting

The Company is subject to the accounting and reporting requirements of the SEC. In addition, the Company's electric utility operations are subject to regulation by the Pennsylvania Public Utility Commission (PUC), including regulation under the *Pennsylvania Electricity Generation Customer Choice and Competition Act* (Customer Choice Act), and the FERC under the *Federal Power Act* with respect to rates for interstate sales, transmission of electric power, accounting and other matters.

The Company's consolidated financial statements report regulatory assets and liabilities in accordance with *Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), and reflect the effects of the current ratemaking process. In accordance with SFAS No. 71, the Company's consolidated financial statements reflect regulatory assets and liabilities consistent with cost-based, pre-competition ratemaking regulations. (See "Rate Matters," Note E, on page 58.)

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 from Sales of Electricity

The Company's electric utility operations provide service to customers in Allegheny County, including the City of Pittsburgh; Beaver County; and Westmoreland County. (See "Rate Matters," Note E, on page 58.) This territory represents approximately 800 square miles in southwestern Pennsylvania, located within a 500-mile radius of one-half of the population of the United States and Canada. 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 direct customers, the Company's utility operations also sell electricity to other utilities.

Meters are read monthly and electric utility 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. (See "Energy Cost Rate Adjustment Clause (ECR)" discussion below.)

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). Under the Company's mitigation plan approved by the PUC in June 1996, the level of energy cost recovery is capped at 1.47 cents per kilowatt-hour (KWH) through May 2001. The rate currently being recovered is 1.28 cents per KWH, based upon estimated 1996 costs. To the extent that current fuel and purchased power costs, in combination with previously deferred fuel and purchased power costs, are not projected to be recoverable through this pricing mechanism, these costs would become transition costs subject to recovery through a competitive transition charge (CTC). (See "Rate Matters," Note E, on page 58.) 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 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. This adjustment was not made during 1997, despite a projected increase of 0.13 cents per KWH, pending the outcome of the Company's Restructuring Plan or Stand-Alone Plan (as defined in "Rate Matters," Note E, on page 58).

Over- or under-recoveries from customers have been recorded in the consolidated balance sheet as payable to, or receivable from, customers. Based on Duquesne's Restructuring Plan and Stand-Alone Plan, the 1997 under-recoveries were reclassified as a regulatory asset and may be recovered through a CTC. At December 31, 1997, $23.5 million was receivable from customers. At December 31, 1996, $1.8 million was payable to customers and shown as other current liabilities.

Maintenance

Incremental maintenance costs incurred for refueling outages at the Company's nuclear units are deferred for amortization over the period between refueling outages (generally 18 months). The Company accrues, over the periods between outages, anticipated costs 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.

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. Amortization of limited partnership interests in gas reserve investments and depreciation of related property are on a units of production method over the total estimated gas reserves. Amortization of interests in affordable housing partnerships is based upon a method that approximates the equity method and amortization of certain other leases is on the basis of benefits recorded over the lives of the investments. Depreciation and amortization of other properties are calculated on various bases.

In 1987, the Company sold its 13.74 percent interest in Beaver Valley Unit 2 and leased it back. The lease is accounted for as an operating lease. In May 1997, the Company accelerated the recognition of expense related to the lease. The accelerated expense recognition accounted for $16.1 million of total amortization expense for 1997. Due to the above-market price of the lease, the Company has proposed in its Restructuring Plan and Stand-Alone Plan (as defined in "Rate Matters," Note E, on page 58) to recover the remaining above-market lease costs through a CTC.

The Company records nuclear decommissioning costs under the category of depreciation and amortization expense and accrues a liability, equal to that amount, for nuclear decommissioning expense. 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. Trust fund earnings increase the fund balance and the recorded liability. (See "Nuclear Decommissioning" discussion, Note I, on page 64.)

The Company's electric utility operations' composite depreciation rate increased from 3.5 percent to 4.25 percent effective May 1, 1996. Also in 1996, the Company expensed $9 million related to the depreciation portion of deferred rate synchronization costs in conjunction with the Company's 1996 PUC-approved mitigation plan.

Income Taxes

The Company uses the liability method 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. The deferred tax liability or asset is also adjusted in the period of enactment for the effect of changes in tax laws or rates.

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 E, and "Income Taxes," Note G, on pages 58 and 62.)

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 are deferred. Such credits are subsequently reflected, over the lives of the related assets, as reductions to income tax expense.

Other Operating Revenues and Other Income

Other operating revenues include the Company's non-KWH utility revenues and revenues from market-based operating activities. Other income primarily is made up of income from long-term investments entered into by the market-driven businesses. The income is separated from other revenues as the investment income does not result from operating activities.

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.

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.

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.

Earnings Per Share

SFAS No. 128, Earnings Per Share (SFAS No. 128), establishes standards for computing and presenting earnings per share and makes the standards comparable to international earnings per share standards. It replaces the presentation of primary earnings per share, as found in *Accounting Principles Board (APB) Opinion No. 15, Earnings per Share*, with a presentation of basic earnings per share. It also requires dual presentation of basic and diluted earnings per share on the statement of consolidated income for all entities with complex capital structures. Basic earnings per share is computed by dividing income available to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shared in the earnings of the entity. The statement is effective for financial statements issued for periods ending after December 15, 1997.

The preference stock of the ESOP, as described in Note M, "Employee Benefits," was the primary cause for the dilution of earnings per share for the years ended December 31, 1997, 1996 and 1995 as shown on the statement of consolidated income. Each share of the preference stock is exchangeable for one and one-half shares of DQE common stock. Assuming conversion at the beginning of each year, the number of DQE shares was added to the denominator (weighted-average number of common shares outstanding). Partially offsetting the dilutive effect of the additional shares, the preference stock has an annual dividend rate of $2.80 per share, which was added back to the numerator (income available to common stockholders). The result of calculating both basic and dilutive earnings per share for the three years presented was a $0.03 dilutive effect in each year.

Stock-Based Compensation

The Company accounts for stock-based compensation using the intrinsic value method prescribed in *APB Opinion No. 25, Accounting for Stock Issued to Employees,* and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the quoted market price of the Company's stock at the date of the grant over the amount any employee must pay to acquire the stock. Compensation cost for stock appreciation rights is recorded annually based on the quoted market price of the Company's stock at the end of the period.

Reclassification

The 1996 and 1995 consolidated financial statements have been reclassified to conform with accounting presentations adopted during 1997.

Recent Accounting Pronouncements

SFAS No. 130, Reporting Comprehensive Income (SFAS No. 130) and *SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information* (SFAS No. 131), have been issued and are effective for fiscal years beginning after December 15, 1997. SFAS No. 130 defines comprehensive income and outlines certain reporting and disclosure requirements related to comprehensive income. SFAS No. 131 requires certain disclosures about business segments of an enterprise, if applicable. The adoption of SFAS No. 130 and SFAS No. 131 is not expected to have a significant impact on the Company's financial statements or disclosures.

B. Changes in Working Capital Other than Cash

Changes in Working Capital Other than Cash
(Net of 1997 Chester Disposition and 1996 GSF Energy Acquisition)

	1997	1996	1995
	(Amounts in Thousands of Dollars)		
Receivables	$(14,947)	$ (1,946)	$ 34,341
Materials and supplies	(1,740)	1,286	9,994
Other current assets	(519)	(948)	3,126
Accounts payable	(4,993)	4,691	7,087
Other current liabilities	(15,030)	(168)	(19,673)
Total	$(37,229)	$ 2,915	$ 34,875

C. Property, Plant and Equipment

In addition to its wholly owned generating units, the Company, together with FirstEnergy Corporation, 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, 1997

Unit	Generating Capability *(Megawatts)*	Net Utility Plant *(Millions of Dollars)*	Fuel Source
Cheswick	570	$ 120.4	Coal
Elrama (a)	487	96.5	Coal
Eastlake Unit 5	186	35.6	Coal
Sammis Unit 7	187	46.7	Coal
Bruce Mansfield Unit 1 (a)	228	62.5	Coal
Bruce Mansfield Unit 2 (a)	62	18.2	Coal
Bruce Mansfield Unit 3 (a)	110	47.9	Coal
Beaver Valley Unit 1 (b)	385	195.9	Nuclear
Beaver Valley Unit 2 (c)(d)	113	14.0	Nuclear
Beaver Valley Common Facilities		149.5	
Perry Unit 1 (e)	164	387.1	Nuclear
Brunot Island Units 2a and 2b	178	21.9	Fuel Oil
Total Generating Units	2,670	$1,196.2	

(a) The unit is equipped with flue gas desulfurization equipment.
(b) The Nuclear Regulatory Commission (NRC) has granted a license to operate through January 2016.
(c) In 1987, the Company sold and leased back its 13.74 percent interest in Beaver Valley Unit 2. The lease is accounted for as an operating lease. Amounts shown represent facilities not sold and subsequent leasehold improvements.
(d) The NRC has granted a license to operate through May 2027.
(e) The NRC has granted a license to operate through March 2026.

D. Long-Term Investments

The Company makes equity investments in affordable housing and gas reserve partnerships as a limited partner. At December 31, 1997, the Company had investments in 27 affordable housing funds and eight gas reserve partnerships. The Company is the lessor in nine leveraged lease arrangements involving mining equipment, rail equipment, fossil generating stations, a waste-to-energy facility, high speed service ferries and natural gas processing equipment. These leases expire in various years beginning in 2004 through 2033. The recorded residual value of the equipment at the end of the lease terms is estimated to be approximately 2 percent of the original cost. The Company's aggregate investment represents 20 percent of the aggregate original cost of the property and is either leased to a creditworthy lessee or is secured by guarantees of the lessee's parent or affiliate. The remaining 80 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 $950 million and $553 million at December 31, 1997 and 1996.

Net Leveraged Lease Investments at December 31

	1997	1996
	(Amounts in Thousands of Dollars)	
Rentals receivable (net of non-recourse debt)	$638,030	$215,358
Estimated residual value of leased assets	22,029	22,029
Less: Unearned income	(310,930)	(103,254)
Leveraged lease investments	349,129	134,133
Less: Deferred taxes arising from leveraged leases	(115,383)	(59,781)
Net Leveraged Lease Investments	$233,746	$ 74,352

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. In accordance with *SFAS 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. The amount of unrealized holding gains related to marketable securities was $8.1 million ($4.7 million net of tax) at December 31, 1997. The amount of unrealized holding losses related to marketable securities was $4.4 million ($2.6 million net of tax) at December 31, 1996. Deferred income primarily relates to the Company's other lease investments and certain gas reserve investments. Deferred amounts will be recognized as income over the lives of the underlying investments for periods generally not exceeding seven years.

In 1997, the Company acquired 100 percent of the Class A Stock of AquaSource, Inc. (AquaSource), which was formed to acquire small and mid-sized water, wastewater and water services companies, with its initial focus in Texas. The Company created the Preferred Stock, Series A (Convertible), $100 liquidation preference per share (DQE Preferred Stock), to issue as consideration in lieu of cash in connection with acquisitions by the Company of other businesses, assets or securities. (See "Preferred and Preference Stock," Note K, on page 68.) At December 31, 1997, the Company had invested approximately $7 million (of which approximately $1.5 million was in the form of DQE Preferred Stock) to acquire the stock or assets of seven water, wastewater and water services companies. In February 1998, the Company issued 159,732 shares of DQE Preferred Stock, representing an investment of approximately $16 million in a water company. The Company has committed approximately $24 million for additional investments in water, wastewater and water services companies for the first quarter of 1998.

E. Rate Matters

Competition and the Customer Choice Act

The electric utility industry continues to undergo fundamental change in response to development of open transmission access and increased availability of energy alternatives. Under historical ratemaking practice, regulated electric utilities were granted exclusive geographic franchises to sell electricity in exchange for making investments and incurring obligations to serve customers under the then-existing regulatory framework. Through the ratemaking process, those prudently incurred costs were recovered from customers along with a return on the investment. Additionally, certain operating costs were approved for deferral for future recovery from customers (regulatory assets). As a result of this historical ratemaking process, utilities have assets recorded on their balance sheets at above-market costs, thus creating transition or stranded costs.

In Pennsylvania, the Customer Choice Act went into effect January 1, 1997. The Customer Choice Act enables Pennsylvania's electric utility customers to purchase electricity at market prices from a variety of electric generation suppliers (customer choice). Although the Customer Choice Act will give customers their choice of electric generation suppliers, delivery of the electricity from the generation supplier to the customer will remain the responsibility of the existing franchised utility. The Customer Choice Act also provides that the existing franchised utility may recover, through a CTC, an amount of transition or stranded costs that are determined by the PUC to be just and reasonable. Pennsylvania's electric utility restructuring is being accomplished through a two-stage process consisting of an initial customer choice pilot period (running through 1998) and a phase-in to competition period (beginning in 1999). For the first stage, the Company filed a pilot program with the PUC on February 27, 1997. For the second stage, the Company filed on August 1, 1997 its restructuring and merger plan (the Restructuring Plan) and its stand-alone restructuring plan (the Stand-Alone Plan) with the PUC. (See the detailed discussion of these plans on pages 59 and 60.)

Customer Choice Pilots

The pilot period gives utilities an opportunity to examine a wide range of technical and administrative details related to competitive markets, including metering, billing, and cost and design of unbundled electric services. The Company pilot filing proposed unbundling transmission, distribution, generation and competitive transition charges and offered participating customers the same options that were to be available in a competitive generation market. The pilot was designed to comprise approximately 5 percent of the Company's residential, commercial and industrial demand. The 28,000 customers participating in the pilot may choose unbundled service, with their electricity provided by an alternative generation supplier, and will be subject to unbundled distribution and CTC charges approved by the PUC and unbundled transmission charges pursuant to the Company's FERC-approved tariff. On May 9, 1997, the PUC issued a Preliminary Opinion and Order approving the Company's filing in part, and requiring certain revisions. The Company and other utilities objected to several features of the PUC's Preliminary Opinion and Order. Hearings on several key issues were held in July. The PUC issued its final order on August 29, 1997, approving a revised pilot program for the Company. On September 8, 1997, the Company appealed the determination of the market price of generation set forth in this order to the Commonwealth Court of Pennsylvania. The Company expects a hearing to be scheduled for mid-1998. Although this appeal is pending, the Company complied with the PUC's order to implement the pilot program that began on November 3, 1997.

Phase-In to Competition

The phase-in to competition begins on January 1, 1999, when 33 percent of customers will have customer choice (including customers covered by the pilot program); 66 percent of customers will have customer choice no later than January 1, 2000; and all customers will have customer choice no later than January 1, 2001. However, in its sole order to date (the PECO Order), the PUC ordered the phase-in provisions of the Customer Choice Act to require the acceleration of the second and third phases to January 2, 1999 and January 2, 2000, respectively. As they are phased-in, customers that have chosen an electricity generation supplier other than the Company will pay that supplier for generation charges, and will pay the Company a CTC (discussed below) and unbundled charges for transmission and distribution. Customers that continue to buy their generation from the Company will pay for their service at current regulated tariff rates divided into unbundled generation, transmission and distribution charges. The PECO Order concluded that under the Customer Choice Act, an electric distribution company, such as Duquesne is to remain a regulated utility and may only offer PUC-approved, tariffed rates (including unbundled generation rates). Delivery of electricity (including transmission, distribution and customer service) will continue to be regulated in substantially the same manner as under current regulation.

Rate Cap and Transition Cost Recovery

Before the phase-in to customer choice begins in 1999, the PUC expects utilities to take vigorous steps to mitigate transition costs as much as possible without increasing the rates they currently charge customers. The Company has mitigated in excess of $350 million of transition costs during the past three years through accelerated annual depreciation and a one-time write-down of nuclear generating station costs, accelerated recognition of nuclear lease costs, increased nuclear decommissioning funding, and amortization of various regulatory assets. This relative level of transition cost reduction, while holding rates constant, is unmatched within Pennsylvania.

The PUC will determine what portion of a utility's transition or stranded costs that remain at January 1, 1999 will be recoverable through a CTC from customers. The CTC recovery period could last through 2005, providing a utility a total of up to nine years beginning January 1, 1997 to recover transition costs, unless this period is extended as part of a utility's PUC-approved transition plan. An overall four-and-one-half-year rate cap from January 1, 1997 will be imposed on the transmission and distribution charges of electric utility companies. Additionally, electric utility companies may not increase the generation price component of rates as long as transition costs are being recovered, with certain exceptions. The Company has requested recovery of transition costs of approximately $2 billion, net of deferred taxes, beginning January 1, 1999. Of this amount, $0.5 billion represents regulatory assets and $1.5 billion represents potentially uneconomic plant and plant decommissioning costs. Any estimate of the ultimate level of transition costs for the Company depends on, among other things, the extent to which such costs are deemed recoverable by the PUC, the ongoing level of the cost of Duquesne's operations, regional and national economic conditions, and growth of the Company's sales. (See "Financial Exposure to Transition Cost Recovery" discussion on page 40 and "Regulatory Assets and Emerging Issues Task Force" discussion on page 61).

Timetable for Restructuring Plan and Stand-Alone Plan Approval

On August 1, 1997, the Company filed the Restructuring Plan and the Stand-Alone Plan with the PUC. Although the provisions of the Customer Choice Act require a PUC decision nine months from the filing date (which would be April 30, 1998), the Pennsylvania Attorney General's Office requested an extension in order to conduct an investigation into certain competition issues relating to the Restructuring Plan. Pursuant to an arrangement among the Company, the PUC and the Attorney General, the Company anticipates a decision by the PUC (with respect to the Restructuring Plan if the merger is approved, or with respect to the Stand-Alone Plan if the merger is not approved) on or before May 29, 1998 or such later date as the parties may agree.

Stand-Alone Plan

In the event the merger with AYE is not consummated under the filed Restructuring Plan, the Company has sought approval for restructuring and recovery of its own transition costs through a CTC under the Stand-Alone Plan. The Company proposed that any finding of market value for the Company's generating assets should be based on market evidence and not on an administrative determination of that value based on price forecasts (the PECO Order determined the market value of PECO Energy Company's generation based on the price forecast sponsored by the Pennsylvania Office of Consumer Advocate). In addition, the Company proposed that such a final market valuation be conducted in 2003, and that an annual competitive market solicitation be used to set the CTC in the interim. The 2003 final market valuation would be performed by an independent panel of experts using the best available market evidence at that time. The Stand-Alone Plan filing also provided for certain triggers that would accelerate the date of this final market valuation. Prior to the final valuation, the Company would sell a substantial amount of power to the highest bidder in an annual competitive solicitation. The annual market price established by the solicitation would be used to set competitive generation credits and determine the CTC as a residual from the generation rate cap under the Rate Cap Provision. (See "Financial Impact of Pilot Program Order" discussion on page 38.) During the transition period, the Company committed to accelerate amortization and depreciation of its generation-related assets and cap its return on equity through a return on equity spillover mechanism, in exchange for being allowed to charge existing rates under the Rate Cap Provision. The Company committed to a minimum of $1.7 billion of amortization and depreciation of generation-related assets by the end of 2005. Under the proposed return on equity spillover mechanism, additional amortization and depreciation in excess of this minimum $1.7 billion commitment would be recorded in order to comply with the return on equity cap. The generation rate cap would apply to the sum of the CTC and the competitive generation credit determined in the annual competitive solicitation. The Stand-Alone Plan also proposed to redesign individual tariffs to encourage more efficient consumption and further mitigate transition costs during the transition period. Consistent with the Company's long-standing commitment to economic development, the rate redesign provides for a significant reduction in the cost of electricity for incremental consumption. Application of the rate redesign to the CTC would also have the potential to maximize mitigation of transition costs during the transition period.

As an alternative to a market-based valuation in 2003, if the PUC finds that a determination of market value as of December 31, 1998 is required by the Customer Choice Act, then the Company has agreed that the PUC may order an immediate auction of the Company's generation at that time.

Restructuring Plan

The Restructuring Plan incorporates the benefits of the merger with AYE, such as anticipated savings to the Company, on a nominal basis, of $365 million in generation-related costs over 20 years, and $9 million in transmission-related costs and $173 million in distribution-related costs over 10 years. The Company plans to use the generation-related portion of its share of net operating synergy savings to shorten the transition cost recovery period. The Restructuring Plan also incorporates the market-based approach to determining transition costs proposed by the Company in its Stand-Alone Plan. The 2003 final market valuation will be performed by an independent panel of experts using the best available market evidence at that time, including a potential sale of a portion of the combined company's generating assets. Certain triggers will accelerate the date of this final market valuation if market prices rise significantly or the minimum amortization commitment is satisfied prior to 2003. The annual market price established by the Company's solicitation would be used to set competitive generation credits and to determine the CTC as a residual from the generation rate cap under the Rate Cap Provision. The Company's minimum amortization commitment of $1.7 billion in the proposed Stand-Alone Plan has been increased under the Restructuring Plan. As in the Stand-Alone Plan, the determination of transition costs in 2003 will compare the book value of generating assets in 2005 (after netting the increased minimum commitment to depreciation and amortization and any return on equity spillover) with the market value of the generating assets in 2005. The opposing parties believe that there should be a one-time valuation of the generating assets performed at January 1, 1999. Any merger-related synergies relating to generation would then be used to reduce the Company's transition costs as of that date. These parties also believe that the Company's proposed distribution rate decrease should be effective January 1, 1999, as well.

Additional Restructuring Plan Commitments

The Restructuring Plan also contains a number of commitments by the merged DQE/AYE entity. First, the merged entity will open up its transmission system to all parties on a reciprocal non-discriminatory basis and eliminate multiple rate charges across the combined transmission system. Second, the merged entity will join a recently proposed Midwest Independent System Operator (ISO) or other then-existing ISO, or form its own ISO if no existing ISO offers acceptable rules, including marginal cost transmission rates. Several utilities have applications pending before the FERC to form ISOs. Third, the merged entity has committed to make a report, 18 months after consummation of the merger, to the PUC regarding its progress on the ISO commitment. The PUC may, at its option, require the merged entity to relinquish control of 300 MW of generating capacity to alleviate concerns over market power. The form of relinquishment would be at the option of the merged entity; possible forms of relinquishment include an energy swap, entering a power sale contract, divestiture of generating assets and a bidding trust.

The Federal Filings

In addition to the PUC filings of the Restructuring Plan and the Stand-Alone Plan, on August 1, 1997, the Company and AYE filed their joint merger application with the FERC (the FERC Filing). Pursuant to the FERC Filing, the Company and AYE have committed to forming or joining an ISO that meets the entity's requirements, including marginal cost transmission pricing, following the merger. In addition, the Company and AYE have stated in the FERC Filing that following the merger the combined entity's market share will not violate the market power conditions and requirements set by the FERC. On January 20, 1998, the Company and AYE filed merger applications with the Antitrust Division of the Department of Justice and the Federal Trade Commission. These applications are currently pending.

Regulatory Assets and Emerging Issues Task Force

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.

A company's electric utility operations, or a portion of such operations, could cease to meet the SFAS No. 71 criteria for various reasons, including a change in the FERC regulations or the competition-related changes in the PUC regulations. (See "Competition and the Customer Choice Act," Note E, on page 58.) The Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) has determined that once a transition plan has been approved, application of SFAS No. 71 to the generation portion of a utility must be discontinued and replaced by the application of *SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71* (SFAS No. 101). The consensus reached by the EITF provides further guidance that the regulatory assets and liabilities of the generation portion of a utility to which SFAS No. 101 is being applied should be determined on the basis of the source from which the regulated cash flows to realize such regulatory assets and settle such liabilities will be derived. Under the Customer Choice Act, the Company believes that its generation-related regulatory assets will be recovered through a CTC collected in connection with providing transmission and distribution services, and the Company will continue to apply SFAS No. 71. Fixed assets related to the generation portion of a utility will be evaluated on the cash flows provided by the CTC, in accordance with *SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of* (SFAS No. 121). The Company believes that all of its regulatory assets continue to satisfy the SFAS No. 71 criteria in light of the transition to competitive generation under the Customer Choice Act and the ability to recover these regulatory assets through a CTC. Once any portion of the Company's electric utility operations is deemed to no longer meet the SFAS No. 71 criteria, or is not recovered through a CTC, the Company will be required to write off assets (to the extent their net book value exceeds fair value), the recovery of which is uncertain, and any regulatory assets or liabilities for those operations that no longer meet these requirements. Any such write-off of assets could be materially adverse to the financial position, results of operations and cash flows of the Company.

The Company's regulatory assets related to generation, transmission and distribution as of December 31, 1997 were $561.9 million, $33.2 million and $85.8 million, respectively. At December 31, 1996, the Company's regulatory assets related to generation, transmission and distribution were $492.6 million, $41.4 million and $102.8 million, respectively. The components of all regulatory assets for the periods presented are as follows:

Regulatory Assets at December 31

	1997	1996
	(Amounts in Thousands of Dollars)	
Regulatory tax receivable (Note A)	**$301,664**	$394,131
Brunot Island and Phillips cold reserve units (a)	**105,693**	—
Unamortized debt costs (b)	**87,915**	93,299
Deferred rate synchronization costs (c)	**37,231**	41,446
Beaver Valley Unit 2 sale/leaseback premium (Note H)	**28,554**	30,059
Deferred employee costs (d)	**25,130**	29,589
Deferred energy costs (Note A)	**23,514**	—
Deferred nuclear maintenance outage costs (Note A)	**17,013**	13,462
Deferred coal costs (e)	**15,711**	12,191
DOE decontamination and decommissioning receivable (Note I)	**8,847**	9,779
Other (f)	**29,613**	12,860
Total Regulatory Assets	**$680,885**	$636,816

(a) Through its analysis of customer choice in the Restructuring Plan and Stand-Alone Plan, the Company determined that Phillips and a portion of Brunot Island would not be cost-effective in the production of electricity in the face of a competitive marketplace.

(b) 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.

(c) Initial operating costs of Beaver Valley Unit 2 and Perry Unit 1 were deferred and are currently being recovered over a 10-year period.

(d) Includes amounts for recovery of accrued compensated absences and accrued claims for workers' compensation.

(e) 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.

(f) 1997 amounts include $6.8 million related to *Statement of Position 96-1, Environmental Remediation Liabilities* for the ongoing monitoring of certain of the Company's sites and $6.8 million of one-time costs for the 1997 early retirement plan recorded in accordance with *SFAS No. 88, Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits* and *SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.* (See "Employee Benefits," Note M, on page 70.)

F. Short-Term Borrowing and Revolving Credit Arrangements

At December 31, 1997, the Company had two extendible revolving credit arrangements, including a $125 million facility expiring in June 1998 and a $150 million facility expiring in October 1998. Interest rates can, in accordance with the option selected at the time of the borrowing, be based on prime, Eurodollar or certificate of deposit rates. 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, 1997 and December 31, 1996, there were no short-term borrowings outstanding.

G. Income Taxes

The annual federal corporate income tax returns have been audited by the Internal Revenue Service (IRS) for the tax years through 1992. The IRS is reviewing the Company's 1993 and 1994 returns, and the tax years 1995 and 1996 remain subject to IRS review. The Company does not believe that final settlement of the federal income tax returns for the years 1990 through 1996 will have a materially adverse effect on its financial position, results of operations or cash flows.

Deferred Tax Assets (Liabilities) at December 31

	1997	1996
	(Amounts in Thousands of Dollars)	
Tax benefit – long-term investments	**$ 210,394**	$ 175,427
Gain on sale/leaseback of BV Unit 2	**58,137**	61,131
Investment tax credits unamortized	**40,573**	44,067
Unbilled revenue	**19,637**	19,222
Other	**65,210**	50,648
Deferred tax assets	**393,951**	350,495
Property depreciation	**(712,247)**	(783,851)
Regulatory assets	**(125,171)**	(150,346)
Leveraged leases	**(115,383)**	(59,781)
Loss on reacquired debt unamortized	**(31,360)**	(33,331)
Deferred coal and energy costs	**(15,910)**	(5,054)
Other	**(87,095)**	(77,221)
Deferred tax liabilities	**(1,087,166)**	(1,109,584)
Net Deferred Tax Liabilities	**$ (693,215)**	$ (759,089)

Income Taxes

		1997	1996	1995
		(Amounts in Thousands of Dollars)		
Currently payable:	Federal	**$ 3,911**	$ 85,976	$ 77,667
	State	**31,083**	44,582	29,915
Deferred – net:	Federal	**69,324**	(18,737)	2,550
	State	**(93)**	(14,874)	(5,640)
Investment tax credits deferred – net		**(8,420)**	(9,559)	(7,831)
Income Taxes		**$ 95,805**	$ 87,388	$ 96,661

Total income taxes differ from the amount computed by applying the statutory federal income tax rate to income before income taxes.

Income Tax Expense Reconciliation

	1997	1996	1995
	(Amounts in Thousands of Dollars)		
Computed federal income tax at statutory rate	**$103,217**	$ 93,284	$ 93,528
Increase (decrease) in taxes resulting from:			
State income taxes, net of federal income tax benefits	**20,143**	19,310	15,779
Investment tax benefits – net	**(17,831)**	(15,116)	(5,478)
Amortization of deferred investment tax credits	**(8,420)**	(9,559)	(7,831)
Other	**(1,304)**	(531)	663
Total Income Tax Expense	**$ 95,805**	$ 87,388	$ 96,661

H. 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

	1997	1996
	(Amounts in Thousands of Dollars)	
Nuclear fuel	**$ 92,901**	$ 79,103
Electric plant	**20,761**	20,505
Total	**113,662**	99,608
Less: Accumulated amortization	**(50,725)**	(47,670)
Property Held Under Capital Leases – Net (a)	**$ 62,937**	$ 51,938

(a) Includes $2,874 in 1997 and $2,618 in 1996 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 Company subsequently leased back its interest in the unit for a term of 29.5 years. The lease provides for semi-annual payments and is accounted for as an operating lease. The Company is responsible under the terms of the lease for all costs related to 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, 1997, the deferred balance was approximately $28.6 million.

Leased nuclear fuel is amortized as the fuel is burned and charged to fuel and purchased power expense on the statement of consolidated income. The amortization of all other leased property is based on rental payments made (except the BV Unit 2 lease, see "Depreciation and Amortization" discussion on page 54). These lease-related expenses are charged to operating expenses on the statement of consolidated income.

Summary of Rental Payments

	1997	1996	1995
	(Amounts in Thousands of Dollars)		
Operating leases	**$60,684**	$59,503	$57,617
Amortization of capital leases	**16,847**	19,378	26,705
Interest on capital leases	**3,435**	3,703	4,332
Total Rental Payments	**$80,966**	$82,584	$88,654

Future Minimum Lease Payments

Year Ended December 31,	Operating Leases	Capital Leases
	(Amounts in Thousands of Dollars)	
1998	$ 54,326	$ 26,401
1999	54,319	16,417
2000	54,280	10,446
2001	54,195	4,717
2002	55,746	3,342
2003 and thereafter	810,097	16,649
Total Minimum Lease Payments	$1,082,963	$ 77,792
Less: Amount representing interest		(17,729)
Present value of minimum lease payments for capital leases (a)		$ 60,063

(a) Includes current obligations of $22.5 million at December 31, 1997.

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

Future payments due to the Company, as of December 31, 1997, under subleases of certain corporate office space are approximately $5.9 million in 1998, $6.0 million in 1999 and $27.6 million thereafter.

I. Commitments and Contingencies

Construction and Investments

The Company estimates that it will spend, excluding AFC and nuclear fuel, approximately $130 million during 1998 and $100 million in each of 1999 and 2000 for electric utility construction.

In 1997, the Company formed a strategic alliance with CQ Inc. to produce E-Fuel™, a coal-based synthetic fuel. The first six plants to produce E-Fuel™ are under construction, and are expected to be in operation by mid-1998. The Company estimates the cost of this construction to be approximately $25 million in 1998.

In February 1998, the Company issued 159,732 shares of DQE Preferred Stock, representing an investment of approximately $16 million in a water company. The Company has committed approximately $24 million for additional investments in water, wastewater and water services companies for the first quarter of 1998.

In 1997, the Company entered into a partnership with MCI Communications Corporation. The Company expects this partnership will lead to investment opportunities in the expanding telecommunications business.

Nuclear-Related Matters

The Company has an ownership interest in three nuclear units, two of which it operates. 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 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 in 2016, 2027 and 2026. At the end of its operating life, BV Unit 1 may be placed in safe storage until BV Unit 2 is ready to be decommissioned, at which time the units may be decommissioned together.

Based on site-specific studies conducted in 1997 for BV Unit 1 and BV Unit 2, and a 1997 update of the 1994 study for Perry Unit 1, the Company's approximate share of the total estimated decommissioning costs, including removal and decontamination costs, is $170 million, $55 million and $90 million, respectively. The amount currently being used to determine the Company's cost of service related to decommissioning all three nuclear units is $224 million. The Company is seeking recovery of any potential shortfall in decommissioning funding as part of either its Restructuring Plan or its Stand-Alone Plan. (See "Rate Matters," Note E, on page 58.)

With respect to the transition to a competitive generation market, the Customer Choice Act requires that utilities include a plan to mitigate any shortfall in decommissioning trust fund payments for the life of the facility with any future decommissioning filings. Consistent with this requirement, in 1997 the Company increased its annual contributions to the decommissioning trusts by $5 million to approximately $9 million. The Company has received approval from the IRS for qualification of 100 percent of additional nuclear decommissioning trust funding for BV Unit 2 and Perry Unit 1, and 79 percent for BV Unit 1.

Funding for nuclear decommissioning costs is deposited in external, segregated trust accounts and invested in a portfolio of corporate common stock and debt securities, municipal bonds, certificates of deposit and United States government securities. The market value of the aggregate trust fund balances at December 31, 1997 and 1996, totaled approximately $47.1 million and $33.7 million, respectively.

Nuclear Insurance. 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 maximum available private primary insurance of $200 million has been purchased by the Company. Additional protection of $8.7 billion would be provided by an assessment of up to $79.3 million per incident on each nuclear unit in the United States. The Company's maximum total possible assessment, $59.4 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. This assessment is subject to indexing for inflation and may be subject to state premium taxes. If assessments from the nuclear industry prove insufficient to pay claims, the United States Congress could impose other revenue-raising measures on the industry.

The Company's share of insurance coverage for property damage, decommissioning and decontamination liability is $1.2 billion. 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 that provides a portion of this coverage, 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 $5.8 million.

In addition, the Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Subject to the policy deductible, terms and limit, the coverage provides for a weekly indemnity of the estimated incremental costs during the three-year period starting 21 weeks after an accident, with no coverage thereafter. If NEIL's losses for this program ever exceed its reserves, the Company could be assessed retrospective premiums totaling a maximum of $3.4 million.

Beaver Valley Power Station (BVPS) Steam Generators. BVPS's two units are equipped with steam generators designed and built by Westinghouse Electric Corporation (Westinghouse). Similar to other Westinghouse nuclear plants, outside diameter stress corrosion cracking (ODSCC) has occurred in the steam generator tubes of both units. BV Unit 1, which was placed in service in 1976, has removed approximately 17 percent of its steam generator tubes from service through a process called "plugging." However, BV Unit 1 continues to operate at 100 percent reactor power and has the ability to return tubes to service by repairing them through a process called "sleeving." No tubes at either BV Unit 1 or BV Unit 2 have been sleeved to date. BV Unit 2, which was placed in service 11 years after BV Unit 1, has not yet exhibited the degree of ODSCC experienced at BV Unit 1. Approximately 2 percent of BV Unit 2's tubes are plugged; however, it is too early in the life of the unit to determine the extent to which ODSCC may become a problem at that unit.

The Company has undertaken certain measures, such as increased inspections, water chemistry control and tube plugging, to minimize the operational impact of and to reduce susceptibility to ODSCC. Although the Company has taken these steps to allay the effects of ODSCC, the inherent potential for future ODSCC in steam generator tubes of the Westinghouse design still exists. Material acceleration in the rate of ODSCC could lead to a loss of plant efficiency, significant repairs or the possible replacement of the BV Unit 1 steam generators. The total replacement cost of the BV Unit 1 steam generators is currently estimated at $125 million. The Company would be responsible for $59 million of this total, which includes the cost of equipment removal and replacement steam generators but excludes replacement power costs. The earliest that the BV Unit 1 steam generators could be replaced during a scheduled refueling outage is the fall of 2000.

The Company continues to explore all viable means of managing ODSCC, including new repair technologies, and plans to continue to perform 100 percent tube inspections during future refueling outages. The next refueling outage for BV Unit 1 is scheduled to begin in April 1999, and the next refueling outage for BV Unit 2 is currently scheduled to begin in September 1998. Both outages will include inspection of 100 percent of each unit's steam generator tubes. The Company will continue to monitor and evaluate the condition of the BVPS steam generators.

BV Unit 1 went off-line on September 27, 1997, for a scheduled refueling outage, and returned to service on January 21, 1998. Perry Unit 1 completed a refueling outage on October 23, 1997. This outage lasted 40 days, a record for Perry Unit 1. The next refueling outage for Perry Unit 1 is currently scheduled to begin in March 1999.

BV Unit 1 went off-line January 30, 1998, due to an issue identified in a technical review recently completed by the Company. BV Unit 2 went off-line December 16, 1997, to repair the emergency air supply system to the control room and has remained off-line due to other issues identified by a similar technical review of BV Unit 2. These technical reviews are in response to a 1997 commitment made by the Company to the NRC. The Company is one of many utilities faced with these technical issues, some of which date back to the original design of BVPS. Both BVPS units remain off-line for a revalidation of technical specification surveillance testing requirements of various plant systems. Based on the current status of the revalidation process, the Company currently anticipates that both BVPS units will remain off-line through March 1998.

Spent Nuclear Fuel Disposal. The *Nuclear Waste Policy Act of 1982* established a federal policy for handling and disposing of spent nuclear fuel and a policy requiring the establishment of a final repository to accept spent nuclear 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 nuclear fuel before 2010. The DOE has not yet established an interim or permanent storage facility, despite a ruling by the United States

Court of Appeals for the District of Columbia Circuit that the DOE was legally obligated to begin acceptance of spent nuclear fuel for disposal by January 31, 1998. Existing on-site spent nuclear fuel storage capacities at BV Unit 1, BV Unit 2 and Perry Unit 1 are expected to be sufficient until 2017, 2011 and 2011, respectively.

In early 1997, the Company joined 35 other electric utilities and 46 states, state agencies and regulatory commissions in filing suit in the United States Court of Appeals for the District of Columbia Circuit against the DOE. The parties requested the court to suspend the utilities' payments into the Nuclear Waste Fund and to place future payments into an escrow account until the DOE fulfills its obligation to accept spent nuclear fuel. The DOE had requested that the court delay litigation while it pursued alternative dispute resolution under the terms of its contracts with the utilities. The court ruling, issued November 14, 1997, was not entirely in favor of the DOE or the utilities. The court permitted the DOE to pursue alternative dispute resolution, but prohibited it from using its lack of a spent fuel repository as a defense. The DOE has requested a rehearing on the matter, which has yet to be scheduled.

Uranium Enrichment Obligations. Nuclear reactor licensees in the United States are assessed annually for the decontamination and decommissioning of DOE uranium 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, 1997 and 1996, the Company's liability for contributions was approximately $7.2 million and $8.1 million, respectively (subject to an inflation adjustment). (See "Rate Matters," Note E, on page 58.)

Fossil Decommissioning

In Pennsylvania, current ratemaking does not allow utilities to recover future decommissioning costs through depreciation charges during the operating life of fossil-fired generating stations. Based on studies conducted in 1997, this amount for fossil decommissioning is currently estimated to be $130 million for the Company's interest in 17 units at six sites. Each unit is expected to be decommissioned upon the cessation of the final unit's operations. The Company has submitted these estimates to the PUC, and is seeking to recover these costs as part of either its Restructuring Plan or its Stand-Alone Plan. (See "Rate Matters," Note E, on page 58.)

Guarantees

The Company and the other owners of Bruce Mansfield Power Station (Bruce Mansfield) have guaranteed certain debt and lease obligations related to a coal supply contract for Bruce Mansfield. At December 31, 1997, the Company's share of these guarantees was $15.1 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. The minimum future payments to be made by the Company solely in relation to these obligations are $6.2 million in 1998, $5.8 million in 1999, and $4.6 million in 2000. The Company's total payments for coal purchased under the contract were $38.3 million in 1997, $26.9 million in 1996, and $28.9 million in 1995.

As part of the Company's investment portfolio in affordable housing, the Company has received fees in exchange for guaranteeing a minimum defined yield to third-party investors. 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, the Company believes 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 it utilizes and has developed compliance strategies that are currently under review by the DEP. Capital costs of $2.8 million and $2.5 million were incurred by the Company in 1997 and 1996, respectively, to comply with these DEP regulations. The additional capital cost of compliance through the year 2000 is estimated, based on current information, to be $16 million. This estimate is subject to the results of groundwater assessments and DEP final approval of compliance plans.

Employees

The Company is party to a labor contract expiring in September 2001 with the International Brotherhood of Electrical Workers (IBEW), which represents approximately 2,000 of the Company's employees. The contract provides, among other things, employment security, income protection and 3 percent annual wage increases through September 2000.

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, results of operations or cash flows.

J. Long-Term Debt

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.

Long-Term Debt at December 31

	Interest Rate	Maturity	Principal Outstanding *(Amounts in Thousands of Dollars)* 1997	1996
First mortgage bonds	5.85%-8.75%	1998-2025	**$ 778,000 (a)**	$ 853,000 (b)
Pollution control notes	(c)	2009-2030	**417,985**	417,985
Sinking fund debentures	5%	2010	**2,791**	4,891
Term loans	6.47%-7.47%	2000-2001	**150,000**	150,000
Miscellaneous			**31,017**	17,785
Less: Unamortized debt discount and premium – net			**(3,672)**	(3,915)
Total Long-Term Debt			**$1,376,121**	$1,439,746

(a) Excludes $75.0 million related to current maturities during 1998.
(b) Excludes $50.0 million related to a current maturity during 1997.
(c) The pollution control notes have adjustable interest rates. The interest rates at year-end averaged 3.9 percent in 1997 and 3.7 percent in 1996.

At December 31, 1997, sinking fund requirements and maturities of long-term debt outstanding for the next five years were $75.3 million in 1998, $80.6 million in 1999, $165.2 million in 2000, $85.2 million in 2001, and $0.3 million in 2002.

Total interest and other charges were $115.6 million in 1997, $110.3 million in 1996, and $107.6 million in 1995. Interest costs attributable to long-term debt and other interest were $101.2 million, $99.4 million and $102.4 million in 1997, 1996 and 1995, respectively. Of these amounts, $2.3 million in 1997, $1.2 million in 1996, and $0.7 million in 1995 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 ($381.5 million at December 31, 1997) would become direct obligations of the Company.

At December 31, 1997, 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 $1,474.6 million. The principal amount included in the Company's consolidated balance sheet is $1,455.1 million.

At December 31, 1997 and 1996, the Company was in compliance with all of its debt covenants.

K. Preferred and Preference Stock

Preferred and Preference Stock at December 31

	Call Price Per Share	(Shares and Amounts in Thousands) 1997 Shares	1997 Amount	1996 Shares	1996 Amount
Preferred Stock of DQE:					
4.3% Series A Preferred Stock (a) (b)	—	**12**	**$1,172**	—	—
4.2% Series A Preferred Stock (a) (b)	—	**4**	**376**	—	—
Preferred Stock Series of Subsidiaries:					
3.75% (c) (d) (e)	$51.00	**148**	**7,407**	148	$ 7,407
4.00% (c) (d) (e)	51.50	**550**	**27,486**	550	27,486
4.10% (c) (d) (e)	51.75	**120**	**6,012**	120	6,012
4.15% (c) (d) (e)	51.73	**132**	**6,643**	132	6,643
4.20% (c) (d) (e)	51.71	**100**	**5,021**	100	5,021
$2.10 (c) (d) (e)	51.84	**159**	**8,039**	159	8,039
9.00% (f)	—	**—**	**3,000**	—	3,000
8.375% (g)	—	**6,000**	**150,000**	6,000	150,000
6.5% (h)	—	**—**	**1,000**	—	—
Total Preferred Stock		**7,225**	**216,156**	7,209	213,608
Preference Stock Series of Subsidiaries: (i)					
Plan Series A (e) (j)	36.90	**799**	**28,295**	817	28,997
Total Preference Stock		**799**	**28,295**	817	28,997
Deferred ESOP benefit			**(16,400)**		(19,533)
Total Preferred and Preference Stock			**$228,051**		$223,072

(a) Preferred Stock: 4,000,000 authorized shares; no par value
(b) Convertible; $100 liquidation preference per share
(c) Preferred stock: 4,000,000 authorized shares; $50 par value; cumulative
(d) $50 per share involuntary liquidation value
(e) Non-redeemable
(f) 500 authorized shares; 10 issued $300,000 par value; involuntary liquidation value $300,000 per share; mandatory redemption beginning August 2000
(g) Cumulative Monthly Income Preferred Securities, Series A (MIPS): 6,000,000 authorized shares; $25 involuntary liquidation value
(h) 1,500 authorized shares; 10 issued, $100,000 par value; $100,000 involuntary liquidation value
(i) Preference stock: 8,000,000 authorized shares; $1 par value; cumulative
(j) $35.50 per share involuntary liquidation value

On July 30, 1997, the Company authorized and registered 1,000,000 shares of DQE Preferred Stock. As of December 31, 1997, 15,480 shares of DQE Preferred Stock had been issued and were outstanding. An additional 159,732 shares of DQE Preferred Stock were issued on February 19, 1998. The DQE Preferred Stock ranks senior to the Company's common stock as to the payment of dividends and as to the distribution of assets on liquidations, dissolution or winding-up of the Company. The holders of DQE Preferred Stock are entitled to vote on all matters submitted to a vote of the holders of DQE common stock, voting together with the holders of common stock as a single class. Each share of DQE Preferred Stock is entitled to three votes. Each share of DQE Preferred Stock is convertible at the Company's option into the number of shares of DQE common stock computed by dividing the DQE Preferred Stock's $100 liquidation value by the five-day average closing sales price of DQE common stock for the five trading days immediately prior to the conversion date. Each unredeemed share of DQE Preferred Stock will automatically be converted on the first day of the first month commencing after the sixth anniversary of its issuance. If the proposed merger with AYE occurs prior to any conversion, each share of DQE Preferred Stock will be convertible into AYE common stock, using the same methodology to calculate the number of shares.

Dividends on DQE Preferred Stock are paid quarterly on each January 1, April 1, July 1 and October 1. 11,720 shares of DQE Preferred Stock are entitled to an annual dividend of 4.3 percent, and in the fourth quarter of 1997 the Company declared an initial quarterly dividend of $1.075 per share, payable January 1, 1998. 3,760 shares of DQE Preferred Stock are entitled to an annual dividend of 4.2 percent, and in the first quarter of 1998 the Company declared a dividend for the period of December 16, 1997 through March 31, 1998 of $1.237 per share, payable April 1, 1998. The recently issued 159,732 shares are entitled to a 4.0 percent annual dividend, and in the first quarter of 1998 the Company declared a dividend for the period February 19, 1998 through March 31, 1998 of $0.444 per share, payable April 1, 1998.

In October 1997, a Duquesne subsidiary issued 10 shares of preferred stock, par value $100,000 per share. The holders of such shares are entitled to a 6.5 percent annual dividend to be paid each September 30. In 1995, another Duquesne subsidiary issued 10 shares of preferred stock, par value $300,000 per share. The holders of such shares are entitled to a 9.0 percent annual dividend paid quarterly.

In May 1996, Duquesne Capital L.P. (Duquesne Capital), a special-purpose limited partnership of which Duquesne is the sole general partner, issued $150.0 million principal amount of 8⅜ percent Monthly Income Preferred Securities (MIPS), Series A, with a stated liquidation value of $25.00. The holders of MIPS are entitled to annual dividends of 8⅜ percent, payable monthly. The sole assets of Duquesne Capital are Duquesne's 8⅜ percent debentures, with a principal amount of $151.5 million. These debt securities may be redeemed at Duquesne's option on or after May 31, 2001. Duquesne has guaranteed the payment of distributions on, and redemption price and liquidation amount in respect of the MIPS to the extent that Duquesne Capital has funds available for such payment from the debt securities. Upon maturity or prior redemption of such debt securities, the MIPS will be mandatorily redeemed. The Company's consolidated balance sheet reflects only the $150.0 million of MIPS.

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. 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, 1997, Duquesne had made all dividend payments. Preferred and preference dividends of subsidiaries included in interest and other charges were $16.7 million, $12.1 million and $5.9 million in 1997, 1996 and 1995. Total preferred and preference stock had involuntary liquidation values of $244.4 million and $242.5 million, which exceeded par by $27.6 million and $28.2 million at December 31, 1997 and 1996.

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 M, on page 70.) 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, 1997, $16.4 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 $1.1 million for 1997, $1.4 million for 1996, and $1.6 million for 1995. These cash contributions were the difference between the ESOP debt service and the amount of dividends on ESOP shares ($2.3 million in 1997, 1996 and 1995). 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 $3.2 million in 1997 and $2.3 million in 1996 and 1995. Although outstanding preferred stock is generally callable on notice of not less than 30 days, at stated prices plus accrued dividends, the outstanding MIPS and preference stock are not currently callable. None of the remaining Duquesne preferred or preference stock issues has mandatory purchase requirements.

L. Common Stock

Changes in the Number of Shares of DQE Common Stock Outstanding

	1997	1996	1995
	(Amounts in Thousands of Shares)		
Outstanding as of January 1	**77,273**	77,556	78,459
Reissuance from treasury stock	**408**	157	83
Repurchase of common stock	**(1)**	(440)	(986)
Outstanding as of December 31	**77,680**	77,273	77,556

The Company has continuously paid dividends on common stock since 1953. The Company's annualized dividends per share were $1.44, $1.36 and $1.28 at December 31, 1997, 1996 and 1995. During 1997, the Company paid a quarterly dividend of $0.34 per share on each of January 1, April 1, July 1 and October 1. The quarterly dividend declared in the fourth quarter of 1997 was increased from $0.34 to $0.36 per share payable January 1, 1998.

Once all dividends on the DQE Preferred Stock have been paid, 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 and by obligations of Duquesne's subsidiaries to holders of their preferred securities. 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 shareholder's 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 on its common stock or DQE Preferred Stock. No part of the retained earnings of the Company was restricted at December 31, 1997.

M. Employee Benefits

Retirement Plans

The Company maintains retirement plans to provide pensions for all eligible 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 *Employee Retirement Income Security Act of 1974* (ERISA) but that does not exceed the maximum tax-deductible amount for the year. Pension costs charged to expense or construction were $12.7 million for 1997, $11.9 million for 1996, and $6.1 million for 1995.

In 1997, the Company offered an early retirement plan to its bargaining unit employees meeting certain age and service criteria. In accordance with *SFAS No. 88, Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits* and *SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions*, the Company recorded $6.8 million of one-time costs as a regulatory asset and other non-current liability on the consolidated balance sheet.

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

	1997	1996
	(Amounts in Thousands of Dollars)	
Actuarial present value of benefits rendered to date:		
Vested benefits	**$460,483**	$413,109
Non-vested benefits	**25,080**	22,551
Accumulated benefits obligations based on compensation to date	**485,563**	435,660
Additional benefits based on estimated future salary levels	**68,739**	61,438
Projected benefits obligation	**554,302**	497,098
Fair market value of plan assets	**605,457**	525,871
Projected benefits obligation under plan assets	**$ 51,155**	$ 28,773
Unrecognized net gain	**$153,682**	$128,382
Unrecognized prior service cost	**(39,800)**	(43,790)
Unrecognized net transition liability	**(12,039)**	(13,853)
Net pension liability per consolidated balance sheet	**(50,688)**	(41,966)
Total	**$ 51,155**	$ 28,773
Assumed rate of return on plan assets	**8.00%**	8.25%
Discount rate used to determine projected benefits obligation	**7.00%**	7.50%
Assumed change in compensation levels	**4.75%**	5.25%

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

Components of Net Pension Cost

	1997	1996	1995
	(Amounts in Thousands of Dollars)		
Service cost (benefits earned during the year)	**$ 12,340**	$ 12,209	$ 9,953
Interest on projected benefits obligation	**36,570**	32,597	30,063
Return on plan assets	**(95,444)**	(58,173)	(99,246)
Net amortization and deferrals	**65,801**	25,312	65,316
Net Pension Cost	**$ 19,267**	$ 11,945	$ 6,086

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 6 percent of an employee's eligible salary. The Company match consists of a $0.25 base match per eligible contribution dollar and an additional $0.25 incentive match per eligible contribution dollar, if Board-approved targets are achieved. The 1997 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," Note K, on page 68.)

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 4 percent of an employee's eligible salary. The Company match consists of a $0.25 base match per eligible contribution dollar and an additional $0.25 incentive match per eligible contribution dollar, if certain targets are met. In 1997, the incentive target was accomplished.

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 2006, up to a total of 7.5 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, 1997, approximately two million of these shares were available for future grants.

As of December 31, 1997, 1996 and 1995, active grants totaled 1,084,041; 1,698,000; and 2,159,000 shares. Exercise prices of these options ranged from $15.8334 to $33.7813 at December 31, 1997; from $8.2084 to $30.875 at December 31, 1996; and from $8.2084 to $27.625 at December 31, 1995. Expiration dates of these grants ranged from 2000 to 2007 at December 31, 1997; from 1997 to 2006 at December 31, 1996; and from 1997 to 2005 at December 31, 1995. As of December 31, 1997, 1996 and 1995, stock appreciation rights (SARs) had been granted in connection with 635,995; 984,000; and 1,202,000 of the options outstanding. During 1997, 694,984 SARs were exercised; 638,494 options were exercised at prices ranging from $8.2084 to $30.75; and no options were cancelled. During 1996, 715,000 SARs were exercised; 267,000 options were exercised at prices ranging from $8.2084 to $20.3334; and 150 options were cancelled. 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. Of the active grants at December 31, 1997, 1996 and 1995, 402,816; 668,000; and 929,000 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. Participating retirees make contributions, which may be 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.

The Company accrues the actuarially determined costs of the aforementioned postretirement benefits over the period from the date of hire until the date the employee becomes fully eligible for benefits. The Company has elected to amortize the transition liability over 20 years.

Components of Postretirement Cost

	1997	1996
	(Amounts in Thousands of Dollars)	
Service cost (benefits earned during the period)	**$1,603**	$1,182
Interest cost on accumulated benefit obligation	**3,048**	2,046
Amortization of the transition obligation over 20 years	**1,686**	1,700
Other	**218**	(812)
Total Postretirement Cost	**$6,555**	$4,116

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 at December 31

	1997	1996
	(Amounts in Thousands of Dollars)	
Actuarial present value of benefits:		
Retirees	**$ 8,150**	$ 8,840
Fully eligible active plan participants	**5,966**	3,829
Other active plan participants	**32,214**	26,352
Accumulated postretirement benefit obligation	**46,330**	39,021
Fair market value of plan assets	**—**	—
Accumulated benefit obligation in excess of plan assets	**$(46,330)**	$(39,021)
Unrecognized net actuarial (loss) gains	**$ (1,208)**	$ 2,874
Unrecognized net transition liability	**(25,294)**	(27,198)
Postretirement liability per consolidated balance sheet	**(19,828)**	(14,697)
Total	**$(46,330)**	$(39,021)
Discount rate used to determine projected benefit obligation	**7.00%**	7.50%
Health care cost trend rates:		
For year beginning January 1	**6.58%**	6.96%
Ultimate rate in the year 2001	**5.50%**	6.00%
Effect of a one percent increase in health care cost trend rates:		
On accumulated projected benefit obligation	**$ 5,234**	$ 2,920
On aggregate of annual service and interest costs	**$ 581**	$ 391

N. 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 utility's service territory.]

1997	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues (a)	**$303,584**	**$285,861**	**$331,203**	**$298,526**
Operating Income (a)	**76,817**	**56,392**	**96,448**	**51,080**
Net Income	**45,097**	**46,778**	**58,665**	**48,561**
Basic Earnings Per Share	**0.58**	**0.61**	**0.75**	**0.63**
Diluted Earnings Per Share	**0.57**	**0.60**	**0.75**	**0.62**
Stock Price:				
High	**29⅞**	**29**	**33 9/16**	**35⅛**
Low	**27¾**	**26⅞**	**31 7/16**	**30 7/16**

1996	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating Revenues (a)	$300,518	$293,357	$335,430	$296,890
Operating Income (a)	71,316	67,385	104,891	59,414
Net Income	42,305	38,972	57,412	40,449
Basic Earnings Per Share	0.55	0.50	0.74	0.53
Diluted Earnings Per Share	0.54	0.49	0.74	0.52
Stock Price:				
High	31½	28⅞	28¾	30⅜
Low	27½	25¾	27	27

(a) Restated to conform with presentations adopted during 1997.