CATEGORY 1

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AUTH.NAME AUTHOR AFFILIATION
CONWAY,J.T. Niagara Mohawk Power Corp.
RECIP.NAME RECIPIENT AFFILIATION
Records Management Branch (Document Control Desk)

See Financial Rpts.

SUBJECT: Forwards 1997 annual financial repts of NMP & co-tenant companies of RG&E,NYSEG,CHGE & LILCO,per 10CFR50.71(b).Amend 2 to Form 10-K/A,encl.W/o NMP & LILCO annual repts.

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TITLE: 50.71(b) Annual Financial Report

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Niagara Mohawk

T. Conway
resident
Nuclear Generation

Office: (315) 349-4213
Fax: (315) 349-2605

June 30, 1998
NMP1L 1336

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

RE:	Nine Mile Point Unit 1 Docket No. 50-220 DPR-63	Nine Mile Point Unit 2 Docket No. 50-410 NPF-69

Subject: *1997 Annual Financial Reports of Niagara Mohawk and the Co-Tenant Companies of Nine Mile Point Unit 2*

Gentlemen:

Pursuant to Section 50.71(b) of the regulations of the Nuclear Regulatory Commission (10CFR§50.71(b)), enclosed is a copy of the 1997 Annual Financial Report of Niagara Mohawk Power Corporation (NMPC), together with an amended (Amendment No. 2) 1997 Annual Financial Report for NMPC.

Also enclosed are copies of the Annual Financial Reports of Nine Mile Point Unit 2 Co-Tenant companies: Rochester Gas and Electric, New York State Electric & Gas, Central Hudson Gas & Electric, and Long Island Lighting Company.

Very truly yours,

John T. Conway

J.T. Conway
Vice President - Nuclear Generation

1/1
M004

JTC/LMC/sc
Enclosures

xc: w/o enclosures
Mr. H. J. Miller, Regional Administrator, Region I
Mr. S. S. Bajwa, Director, Project Directorate I-1, NRR
Mr. D. S. Hood, Senior Project Manager, NRR
Mr. B. S. Norris, Senior Resident Inspector
Records Management

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 1997

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from .... to ....

Commission file number 1-2987

NIAGARA MOHAWK POWER CORPORATION

(Exact name of registrant as specified in its charter)

State of New York	**15-0265555**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
300 Erie Boulevard West Syracuse, New York	**13202**
(Address of principal executive offices)	(Zip code)

(315) 474-1511
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:
(Each class is registered on the New York Stock Exchange)

Title of each class

Common Stock ($1 par value)

Preferred Stock ($100 par value - cumulative)			Preferred Stock ($25 par value - cumulative)
3.40% Series	4.10% Series	6.10% Series	9.50% Series
3.60% Series	4.85% Series	7.72% Series	Adjustable Rate Series A & Series C
3.90% Series	5.25% Series		

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [x] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [x]

State the aggregate market value of the voting stock held by non-affiliates of the registrant.

Approximately $1,800,000,000 at March 26, 1998.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common stock, $1 par value, outstanding at March 26, 1998: 144,419,351 shares.

NIAGARA MOHAWK POWER CORPORATION

INFORMATION REQUIRED IN FORM 10-K

Part I

Part II

Part III

Part IV

NIAGARA MOHAWK POWER CORPORATION
GLOSSARY OF TERMS

TERM	DEFINITION
AFC	Allowance for Funds Used During Construction
BTU	British Thermal Units
Clean Air Act	Clean Air Act Amendments of 1990
CNG	CNG Transmission Corporation
CNP	Canadian Niagara Power Company, Limited
COPS	Competitive Opportunities Proceeding
CTC	Competitive Transition Charges
CWIP	Construction Work in Progress
DEC	New York State Department of Environmental Conservation
DOE	U.S. Department of Energy
Dth	Dekatherm: one thousand cubic feet of gas with a heat content of 1,000 British Thermal Units per cubic foot
EBITDA	Earnings before Interest Charges, Interest Income, Income Taxes, Depreciation and Amortization (a non-GAAP measure of cash flow)
EPA	U.S. Environmental Protection Agency
FAC	Fuel Adjustment Clause: a clause in a rate schedule that provides for an adjustment to the customer's bill if the cost of fuel varies from a specified unit cost
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GRT	Gross Receipts Tax
GWh	Gigawatt-hour: one gigawatt-hour equals one billion watt-hours
IPP	Independent Power Producer: any person that owns or operates, in whole or in part, one or more Independent Power Facilities
IPP Party	Independent Power Producers that are a party to the MRA
ISO	Independent System Operator
KW	Kilowatt: one thousand watts
KWh	Kilowatt-hour: a unit of electrical energy equal to one kilowatt of power supplied or taken from an electric circuit steadily for one hour
MERIT	Measured Equity Return Incentive Term
MGP	Manufactured Gas Plant
MRA	Master Restructuring Agreement - an agreement to terminate, restate or amend IPP Party power purchase agreements
MRA regulatory asset	Recoverable costs to terminate, restate or amend IPP Party contracts, which are deferred and amortized under PowerChoice
MW	Megawatt: one million watts
MWh	Megawatt-hour: one thousand kilowatt-hours
NO_x	Nitrogen Oxide: gases formed in great part from atmospheric nitrogen and oxygen when combustion takes place under conditions of high temperature and high pressure; considered a major air pollutant

NPL	Federal National Priorities List for Uncontrolled Hazardous Waste Sites
NYS Supreme Court	Supreme Court of the State of New York, Albany County
NRC	U.S. Nuclear Regulatory Commission
NYPA	New York Power Authority
NYPP	New York Power Pool
NYPP Member Systems	Eight Member Systems are: the seven New York State investor-owned electric utilities and NYPA
NYSERDA	New York State Energy Research and Development Authority
PowerChoice agreement	Company's five-year electric rate agreement, which incorporates the MRA, approved in February 1998
PPA	Power Purchase Agreement: long-term contracts under which a utility is obligated to purchase electricity from an IPP at specified rates
PRP	Potentially Responsible Party
PSC	New York State Public Service Commission
PURPA	Public Utility Regulatory Policies Act of 1978, as amended. One of five bills signed into law on November 8, 1978, as the National Energy Act. It sets forth procedures and requirements applicable to state utility commissions, electric and natural gas utilities and certain federal regulatory agencies. A major aspect of this law is the mandatory purchase obligation from qualifying facilities.
QF	Qualifying Facility: an individual (or corporation) that owns and/or operates a generating facility but is not primarily engaged in the generation or sale of electric power. QFs are either power production or cogeneration facilities that qualify under Section 201 of PURPA.
ROE	Return on Common Stock Equity
SFAS No. 71	Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 101	Statement of Financial Accounting Standards No. 101 "Regulated Enterprises - Accounting for the Discontinuance of Application of FASB Statement No. 71"
SFAS No. 106	Statement of Financial Accounting Standards No. 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS No. 109	Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes"
SFAS No. 121	Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of"
SFAS No. 130	Statement of Financial Accounting Standards No. 130 "Reporting Comprehensive Income"
SFAS No. 131	Statement of Financial Accounting Standards No. 131 "Disclosures about Segments of an Enterprise and Related Information"
SFAS No. 132	Statement of Financial Accounting Standards No. 132 "Employers' Disclosure about Pensions and Other Postretirement Benefits"
SO_2	Sulfur Dioxide: a colorless gas of compounds of sulfur and oxygen which is produced primarily by the combustion of fossil fuel
stranded costs	Utility costs that may become unrecoverable due to a change in the regulatory environment
Unit 1	Nine Mile Point Nuclear Station Unit No. 1
Unit 2	Nine Mile Point Nuclear Station Unit No. 2

PART I

Item 1. Business.

Niagara Mohawk Power Corporation (the "Company"), organized in 1937 under the laws of New York State, is engaged principally in the business of generation, purchase, transmission, distribution and sale of electricity and the purchase, distribution, sale and transportation of gas in New York State. See Part II, Item 8. Financial Statements and Supplementary Data - "Note 12. Information Regarding the Electric and Gas Businesses."

GENERAL

Until recent years, the electric and gas utility industry operated in a relatively stable business environment, subject to traditional cost-of-service regulation. The investment community, both shareholders and creditors, considered utility securities to be of low risk and high quality. Regulators upheld the utility's exclusive right to provide service in its franchise areas in exchange for the utility company's obligation to provide universal service to customers in its service territory, subject to cost-of-service regulation. Such regulation often encouraged regulators and other governmental bodies to use utilities as vehicles to advance social programs and collect taxes. In general, prices were established based on cost-of-service, including a fair rate of return and utilities were allowed to fully recover all prudently incurred costs. Cash flows were relatively predictable, as was the industry's ability to sustain dividend payout and interest coverage ratios.

Consequently, the Company's current electricity and gas prices reflect traditional utility regulation. As such, the Company's electricity prices have included state-mandated purchased power costs from IPPs, at costs far exceeding the Company's actual avoided costs, as well as the costs of high taxes in the State of New York. Avoided costs are the costs the Company would otherwise incur to generate power if it did not purchase electricity from another source.

While the Company was experiencing rising costs, rapid technological advances have significantly reduced the price of new generation and significantly improved the performance of smaller scale generating units. In addition, the current excess supply of generating capacity has driven down the prices a competitive market would support. Actions taken by other utilities throughout the country to lower their prices, including those in areas with already relatively low prices, increase the threat of industrial relocation and the need to offer discounts to industrial customers.

In 1997, the Company entered into two related agreements that it believes will significantly improve its financial outlook. Pursuant to the Company's PowerChoice agreement, entered into with the PSC, which regulates utilities in the State of New York, the Company has agreed to a five year rate plan and has agreed to divest its fossil and hydro generating assets, representing 4,217 MW of capacity and approximately $1,100 million of net book value. Pursuant to the MRA, the Company and 15 IPPs have agreed to terminate, restate or amend 28 PPAs in exchange for cash, shares of Company common stock and certain financial contracts.

For a discussion of events that occurred during 1997 in the competitive environment, federal and state regulatory initiatives and the Company's efforts to address its competitive disadvantages and deteriorating financial condition, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following topics are discussed under the general heading of "Business." Where applicable, the discussions make reference to the various other items of this Form 10-K.

Topic	Page

In addition, for a discussion of the Company's properties, see Item 2. Properties - "Electric Service" and "Gas Service". For a discussion of the Company's treatment of working capital items, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Financial Position, Liquidity and Capital Resources".

REGULATION AND RATES

Several critical initiatives have been undertaken by various regulatory bodies and the Company that have had, and are likely to continue to have, a significant impact on the reshaping of the Company and the utility industry. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "PSC Competitive Opportunities Proceeding - Electric," "FERC Rulemaking on Open Access and Stranded Cost Recovery," and "Other Federal and State Regulatory Initiatives - PSC Proposal of New IPP Operating and PPA Management Procedures," " - Generic Gas Rate Proceeding" and " - NRC and Nuclear Operating Matters" for a discussion of these other initiatives.

PowerChoice Agreement and the MRA. For a discussion of the PowerChoice agreement and the MRA, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement".

Multi-Year Gas Rate Settlement Agreement and Generic Gas Rate Proceeding. For a discussion of the three-year gas rate settlement agreement that was conditionally approved by the PSC in December 1996, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Other Federal and State Regulatory Initiatives - "Multi-Year Gas Rate Settlement Agreement" and "- Generic Gas Rate Proceeding."

Price Discounts. For a discussion of price discounts offered to customers and the terms of discount agreements, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Other Company Efforts to Address Competitive Challenges - Customer Discounts."

PSC Audit. In September 1996, as a result of the Company's investigation of a contract with a scrap dealer, Joseph Barsuk, Inc. ("Barsuk"), the PSC directed its staff to investigate the prudence of several long term contracts involving scrap metal and the circumstances surrounding the letting and administration of those contracts. In February 1997, the PSC concluded that a more comprehensive investigation was required to ensure that the Company's ethics and internal control procedures are being effectively implemented. The final report on the prudence review was issued on January 21, 1998 and contained various recommendations to strengthen the Company's scrap handling procedures, its ethics program and its internal control processes. Actions are currently underway to address recommendations in the report. Further, the Company will refund to customers between $2.9 million and $3.7 million related to losses from actions by a scrap metal dealer to defraud the Company between 1970 and 1990 and has also committed to continue to strengthen its ethics program and internal controls. The Company is engaged in litigation against Barsuk and a former inside director of the Company who retired in 1988 to recover damages from such dealings, but is unable to determine the outcome of this matter.

IPPs

In 1997, the Company purchased 13,520,000 MWh or about 33% of its total power supply from IPPs. For a discussion of Company efforts to reduce its IPP costs, see Item 3. Legal Proceedings, Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement" and "Other Federal and State Regulatory Initiatives - PSC Proposal of New IPP Operating and PPA Management Procedures" and Part II, Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Long-Term Contracts for the Purchase of Electric Power."

NEW YORK POWER AUTHORITY

The Company presently has contractual rights to purchase electricity from a number of generating facilities owned by the NYPA. In 1997, these purchases amounted to 7,578,000 MWh, or about 19% of the Company's total power supply requirements. The Company credits to its residential customers, pursuant to the terms of the agreements with NYPA, a portion of the low cost power purchased from NYPA hydro power sources. Refer to Part II, Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Long-Term Contracts for the Purchase of Electric Power" for a table that summarizes the NYPA generating source, amounts of power, and the contract expiration dates for NYPA electricity which the Company was entitled to purchase as of January 1, 1998.

On May 23, 1997, the Company signed an agreement with NYPA and the PSC that allows NYPA's current industrial customers to continue to receive their power allocations from NYPA's James A. FitzPatrick nuclear plant. The agreement also protects the Company's remaining customers by generally requiring the reimbursement by NYPA of stranded costs which may result from any NYPA sales above current levels. The agreement enables the State of New York to continue to use NYPA's electricity to keep and create jobs and investment in New York State while protecting the financial interests of the Company. This agreement terminated litigation pending before the PSC and the FERC regarding NYPA's power sales to industrial customers.

OTHER PURCHASED POWER

Power purchased in 1997 from sources other than IPPs and NYPA amounted to 1,844,000 MWh, representing approximately 4% of the Company's total power supply requirements. The Company purchases electricity from the NYPP and other neighboring utilities as needed for economic operation. The price paid for that power is determined by specific contractual terms, based on market prices. Physical limitations of existing transmission facilities, as well as competition with other utilities and availability of energy, impact the amount of power the Company is able to purchase or sell and the price the Company pays or receives for that power.

FUEL FOR ELECTRIC GENERATION

The PowerChoice agreement will eliminate the Company's FAC, which provided for partial pass-through to customers of fuel and purchased power cost fluctuations from amounts forecast. Also, the Company will auction its fossil and hydro generating assets in accordance with the restructuring under PowerChoice. (See Part II, Item 7. Management's Discussion and Analysis of Financial

Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement.")

Coal. The C. R. Huntley and Dunkirk Steam Stations, the Company's only coal fired generating stations, are expected to burn about 1.8 million and 1.4 million tons of coal, respectively, in 1998. The Company purchased its 1997 coal requirements under short-term contracts and anticipates obtaining its total 1998 coal requirements under short-term contracts as well. The average level of coal supply was 25 days, which is managed for supply risk.

The annual average cost of coal burned in 1995, 1996 and 1997 was $1.42, $1.39, and $1.41 respectively, per million BTU, or $36.81, $36.00 and $36.68, respectively, per ton.

See "Environmental Matters - Air."

Natural Gas. The Albany Steam Station has the capability to use natural gas, as well as residual oil, as a fuel for electric generation. This dual-fuel capability permits the use of the lower cost fuel depending on fuel market conditions. During 1995, 1996 and 1997, natural gas was the predominant fuel used. However, generation at this station was curtailed significantly during this period because of the requirement to purchase IPP power and excess capacity in the region. In early 1995, modifications were completed at the Oswego Steam Station that provided a limited capability for using natural gas for electric generation. The Oswego Steam Station's primary fuel is residual oil.

The Company currently purchases all natural gas for the Albany and Oswego Steam Stations from the spot market. This gas is purchased as an interruptible supply; and therefore, colder than normal weather and increased demand for capacity on interstate pipelines by other firm (non-interruptible) gas customers could restrict the amount of gas supplied to the stations.

The Company has a 25% ownership interest in Roseton Steam Station Units No. 1 and 2 (the "Roseton Units"). Both Roseton Units have dual fuel capability with residual oil as the primary fuel and natural gas as the alternate fuel. Central Hudson Gas and Electric Corporation, a co-owner and the operator of the Roseton Steam Station, has one contract for the supply of up to approximately 100,000 Dths per day of natural gas for use at the Roseton Units. The natural gas supply is used primarily during off peak months (April through October of each year), minimizing the exposure to interruption. In 1997, approximately 0.7 million Dth (the Company's share) of gas were used at the Roseton Units.

The annual average cost of natural gas burned by the Company, including the Roseton Steam Station, from 1995 through 1997 was $1.65, $1.96, and $2.50 respectively, per million BTU, or $1.65, $1.96 and $2.50, respectively, per Dth.

Residual Oil. The Company's total requirements for residual oil in 1998 for its Albany and Oswego Steam Stations are estimated at approximately 1.0 million barrels. Fuel sulfur content standards instituted by New York State require 1.5% sulfur content fuel oil to be burned at the Albany Steam Station. Oswego Unit No. 6 requires low sulfur fuel oil (0.7%). Oswego Unit No. 5, which burns 1.5% sulfur fuel oil, was placed on long term cold standby effective March 1994. All oil requirements are met on the spot market. At December 31, 1997, there were approximately 386,000 barrels of oil, or more than a 16-day supply, at the Oswego Steam Station and approximately 350,000 barrels of oil, or a 30-day supply, at the Albany Steam Station, based on recent burn projections.

The average price of Oswego Unit No. 6 oil at January 1, 1998 was approximately $22.00 per barrel for 0.7% sulfur oil. For 1.5% sulfur oil, the average price was approximately $17.50 per barrel at the Albany Steam Station. The fuel oil prices quoted include the $2.95 per barrel petroleum business tax imposed by New York State.

The supply of residual oil for the Roseton Units has been arranged by Central Hudson Gas and Electric Corporation. A requirements contract is currently in place with options to extend the contract period.

The annual average cost of residual oil burned at the Albany, Oswego and Roseton Steam Stations from 1995 through 1997 was $3.41, $3.81 and $4.05, respectively, per million BTU, or $21.66, $24.15 and $25.58, respectively, per barrel.

Nuclear. The supply of fuel for the Company's Nine Mile Point nuclear generating plants involves: (1) the procurement of uranium concentrates, (2) the conversion of uranium concentrates to uranium hexafluoride, (3) the enrichment of the uranium hexafluoride, (4) the fabrication of fuel assemblies and (5) the disposal of spent fuel and radioactive wastes. Agreements for nuclear fuel materials and services for Unit 1 and Unit 2 (in which the Company has a 41% interest) have been made through the following years:

	Unit No. 1	Unit No. 2
Uranium Concentrates	2002	2002
Conversion	2002	2002
Enrichment	2003	2003
Fabrication	2007	2006

Arrangements have been made for procuring a portion of the uranium, conversion and enrichment requirements through the years listed above, leaving the remaining portion of the requirements uncommitted. Enrichment services are under contract with the U.S. Enrichment Corporation for up to 100% of the requirements through the year 2003. Up to approximately 95% and 90% of the uranium and conversion requirements are under contract through the year 2002 for Unit 1 and Unit 2, respectively. The uncommitted requirements for nuclear fuel materials and services are expected to be obtained through long-term contracts or secondary market purchases.

The cost of fuel utilized at Unit 1 for 1995, 1996 and 1997 was $0.61, $0.60 and $0.54 per million BTU, respectively. The cost of fuel utilized at Unit 2 for 1995 through 1997 was $0.51, $0.50 and $0.49 per million BTU, respectively.

For a discussion of nuclear fuel disposal costs and the disposal of nuclear wastes, the recovery of nuclear fuel costs through rates and for further information concerning costs relating to decommissioning of the Company's nuclear generating plants, see Item 8 - Financial Statements and Supplementary Data - "Note 1. Summary of Significant Accounting Policies - Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs" and "Note 3. Nuclear Operations." For a discussion of the Company's plans to form a New York Nuclear Operating Company, see Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement."

GAS DELIVERY

The Company sells, distributes and transports natural gas to a geographic territory that generally extends from Syracuse to Albany. The northern reaches of the system extend to Watertown and Glens Falls. Not all of the Company's distribution areas are physically interconnected with one another by Company-owned facilities. Presently, nine separate distribution areas are connected directly with CNG, an interstate natural gas pipeline regulated by the FERC, via seventeen delivery stations. The Company also has one direct connection with Iroquois Gas Transmission and one with Empire State Pipeline.

GAS SUPPLY

The majority of the Company's gas sales are for residential and commercial space and water heating. Consequently, the demand for natural gas by the Company's customers is primarily seasonal and influenced by weather factors. The Company purchases its natural gas for sale to its customers under firm and short-term spot contracts, which is transported on both firm and interruptible transportation contracts. During 1997, about 92% and 8% of the Company's natural gas supply was purchased under firm contracts and short-term spot contracts, respectively (generally longer than 30 days) (See Part II. Item 8 - Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Gas Supply, Storage and Pipeline Commitments"). In addition, the Company has a commitment with CNG to provide gas storage capability until March 2002. For a discussion of the PSC staff's proposal that natural gas utilities exit the business of purchasing natural gas for customers over the next five years, See Part II. Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations - "Generic Gas Rate Proceeding."

FINANCIAL INFORMATION ABOUT INDUSTRY SEGMENTS

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data - "Note 12. Information Regarding the Electric and Gas Businesses."

ENVIRONMENTAL MATTERS

General. The Company's operations and facilities are subject to numerous federal, state and local laws and regulations relating to the environment including, among other things, requirements concerning air emissions, water discharges, site remediation, hazardous materials handling, waste disposal and employee health and safety. While the Company devotes considerable resources to environmental compliance and promoting employee health and safety, the impact of future environmental health and safety laws and regulations on the Company cannot be predicted with certainty.

In compliance with environmental statutes and consistent with its strategic philosophy, the Company performs environmental investigations and analyses and installs, as required, pollution control equipment, including, among other things, effluent monitoring instrumentation and materials storage/handling facilities designed to prevent or minimize releases of potentially harmful substances. Expenditures for environmental matters for 1997 totaled approximately $37.1 million, of which approximately $5.6 million was capitalized as pollution control equipment or plant environmental surveillance and approximately $31.5 million was charged to operating expense for remediation, operation of environmental monitoring and waste disposal programs. Expenditures for 1998 are estimated to total $41.6 million, of which $9.0 million is expected to be capitalized and $32.6 million charged to operating expense. Anticipated expenditures for 1999 are estimated to total $42.5 million, of which $5.1 million is expected to be capitalized and $37.4 million charged to operating expense. The expenditures for 1998 and 1999 include the estimated costs for the Company's expected proportionate share of the costs for site investigation and remediation of waste sites discussed under "Solid/Hazardous Waste" below. Costs for site investigation and remediation are included in operating expense to the extent actual costs do not exceed the amount provided for in rates, in which case, the excess costs are deferred for future recovery through cost-of-service based rates.

ISO 14001. During 1997, the Company had all of its fossil and nuclear generating assets (the Oswego, Albany, Huntley and Dunkirk Steam Stations and Nine Mile Point) certified to the ISO 14001 environmental management system standard. The registration audits of these facilities was conducted by Advanced Waste Management Systems. The Company's position has been and continues to be that an effective environmental management system is necessary to prudently manage environmental issues and minimize environmental liabilities.

The Company believes that it is probable that costs associated with environmental compliance will continue to be recovered through the ratemaking process. For a discussion of the circumstances regarding the Company's continued ability to recover these types of expenditures in rates, see Part II, Item 8. Financial Statements and Supplementary Data - "Note 2. Rates and Regulatory Issues and Contingencies."

Air. The Company is required to comply with applicable federal and state air quality requirements pertaining to emissions into the atmosphere from its fossil-fuel generating stations and other air emission sources. The Company's four fossil-fired generating stations (the Albany, Huntley, Oswego and Dunkirk Steam Stations) have Certificates to Operate issued by the DEC.

The provisions of the Clean Air Act address attainment and maintenance of ambient air quality standards, mobile sources of air pollution, hazardous air pollutants, acid rain, permits, enforcement, clean air research and other items. The Clean Air Act will continue to have a substantial and increasing impact upon the operation of fossil-fired electric power plants in future years.

The acid rain provisions of the Clean Air Act (Title IV) require that SO_2 emissions from utilities and certain other sources be reduced nationwide by 10 million tons from their 1980 levels and that NO_x emissions be reduced by two million tons from 1980 levels. Emission reductions were to be achieved in two phases - Phase I was to be completed by January 1, 1995 and Phase II will be completed by January 1, 2000.

The Company has two units (Dunkirk 3 and 4) affected in Phase I. Beginning in 1995, the Company was required to reduce SO_2 emissions by approximately 10,000 - 15,000 tons per year and the Company is complying with these requirements by substituting non-Phase I units and relying on reduced utilization of these units to satisfy its emission reduction requirements at Dunkirk 3 and 4.

With respect to NO_x, Title IV of the Clean Air Act requires emission reductions at Dunkirk 3 and 4. Low NO_x burner technology has been installed to meet the new emission limitations. In addition, Title I of the Clean Air Act (Provisions for the Attainment and Maintenance of National Ambient Air Quality Standards) required the installation of reasonably available control technology ("RACT") on all of the Company's coal, oil and gas-fired units by May 31, 1995. Compliance with Title I RACT requirements at the Company's units was achieved by installing low NO_x burners or other combustion control technology.

Phase II requirements associated with Title IV of the Clean Air Act (targeted for the year 2000 and beyond) will require the Company to further reduce its SO_2 emissions at all of its fossil generating units. Possible options for Phase II SO_2 compliance beyond those considered for Phase I compliance include fuel switching, installation of flue gas desulfurization or clean coal technologies, repowering and the use of emission allowances created under the Clean Air Act.

In September, 1994, the states comprising the Northeast Ozone Transport Commission (New York State included) signed a Memorandum of Understanding that calls for each member state to develop regulations for two additional phases of NO_x reduction beyond RACT (referred to as Phase II and Phase III NO_x reductions). In Phase II, air emission sources located in upstate New York (which includes all of the Company's air emission sources) will have to reduce NO_x emissions by May, 1999 by 55 percent relative to 1990 levels. In Phase III, these air emission sources will have to reduce NO_x emissions in May 2003 by 75 percent relative to 1990 levels. The Memorandum of Understanding provides that the specified reductions in Phase III may be modified if evidence shows that alternative NO_x reductions, together with other emission reductions, will satisfy the air quality standard across the region. The DEC will be developing its Phase II NO_x regulations in 1998. The need for and extent of any further reductions needed in Phase III will not be determined until 1999 or later. Until details are available on how the Phase II and Phase III NO_x reductions will be implemented, definitive compliance plans for the Company's fossil generating stations and reliable compliance cost estimates cannot be developed, although such costs could be significant.

Potential air regulatory developments may impact the Company in the future including: (1) a proposed "long range ozone transport" rulemaking for utilities and other NO_x sources in the Northeast and Midwest to substantially reduce their NO_x emissions; and (2) a revised National Ambient Air Quality Standard for Particulate Matter that includes fine particulates.

The Company spent approximately $5 million, $0.1 million, and $0.1 million in capital expenditures in 1995, 1996 and 1997, respectively, on projects at the fossil generation plants associated with Phase I compliance. The Company has included $1.0 million in its 1998 through 2000 construction forecast for Phase II compliance which will become effective January 1, 2000. For a discussion on the Company's plans to sell its fossil and hydro assets, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement." For a discussion of the Company's negotiations with DEC of a Consent Decree addressing past opacity excursions and future opacity compliance issues, see Item 3. Legal Proceedings.

Water. The Company is required to comply with applicable Federal and State water quality requirements, including the Clean Water Act, in connection with the discharge of condenser cooling water and other wastewaters from its steam-electric generating stations and other facilities. Wastewater discharge permits have been issued by DEC for each of its steam-electric generating stations. These permits must be renewed every five years. In addition, hydroelectric facilities are required to obtain Clean Water Act certifications as part of the FERC licensing/relicensing process. Such certifications have been issued or are pending for a substantial portion of the Company's hydroelectric facilities. Conditions of the permits typically require that studies be performed to determine the effects of station operation on the aquatic environment in the station vicinity and to evaluate various technologies for mitigating losses of aquatic life.

Low Level Radioactive Waste. See Part II, Item 8. Financial Statements and Supplementary Data - "Note 3. Nuclear Operations - Low Level Radioactive Waste."

Solid/Hazardous Waste. The public utility industry typically utilizes and/or generates in its operations a broad range of hazardous and potentially hazardous wastes and by-products. The Company believes it is handling identified wastes and by-products in a manner consistent with federal, state and local requirements and has implemented an environmental audit program to identify potential areas of concern and aid in compliance with such requirements. Environmental laws can impose liability for the entire cost of site remediation upon each of the parties that have sent waste to a contaminated site regardless of fault or the lawfulness of the original disposal activity. The Company is also currently investigating and remediating, as necessary to meet current environmental standards, certain properties associated with its former gas manufacturing operations and other properties which the Company has learned may be impacted by industrial waste, as well as investigating identified industrial waste sites where Company waste materials may have been sent. The Company has also been advised that various federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company is currently aware of 124 such sites with which it has been or may be associated, including 76 which are Company-owned. The Company-owned sites include 21 former MGP sites, 10 industrial waste sites and 45 operating property sites where corrective actions may be deemed necessary to prevent, contain and/or remediate impacts to soil and/or water in the vicinity. Of these Company-owned sites, Saratoga Springs is on the NPL published by the EPA. The number of owned sites has increased as the Company has established a program to actively identify and manage potential areas of concern at its electric substations. This effort resulted in identifying an additional 32 sites in 1997. The 48 non-owned sites with which the Company has been or may be associated are generally industrial disposal waste sites where some of the disposed waste materials are alleged to have originated from the Company's operations. Pending the results of investigations at the non-owned sites, the Company may be required to fund some share of the remedial costs. Although one party can, as a matter of law, be held liable for all of the remedial costs at a site, regardless of fault, in practice costs are usually allocated among PRPs.

Investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) if necessary, determine the appropriate remedial actions and (3) where appropriate, identify other parties who should bear some or all of the cost of remediation. Legal action against such other parties will be initiated where appropriate. After site investigations are completed, the Company expects to determine site-specific remedial actions and to estimate the attendant costs for restoration. However, since investigations are ongoing at most sites, the estimated cost of any remedial action is subject to change.

Estimates of the Company's potential liability for Company-owned sites are based upon a variety of factors, including identified or potential contaminants, location, size and use of the site, proximity to sensitive resources, status of regulatory investigation and knowledge of activities and costs at similarly situated sites. Additionally, as further described below, the Company's estimating approach now includes a process for certain sites where these factors are developed and reviewed using direct input and support obtained from the DEC. Actual Company expenditures are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs, as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several. The Company has denied any responsibility at certain of these sites where other PRPs are identified and is contesting liability accordingly.

As a consequence of site characterizations and assessments completed to date, the Company has accrued a liability of $155 million for these owned sites, representing its best current estimate for its share of the costs for investigation and remediation. The high end of the range is presently estimated at approximately $365 million. The amount accrued at December 31, 1997, incorporates the additional electric substations, previously mentioned, and a change in the method used to estimate the liability for 27 of its largest sites, to rely upon a decision analysis approach. This method includes developing several remediation approaches for each of the 27 sites, using the factors previously described, and then assigning a probability to each approach. The probability represents the Company's best estimate of the likelihood of the approach occurring using input received directly from the DEC. The probable costs for each approach are then calculated to arrive at an expected value. While this approach calculates a range of outcomes, the Company has accrued the sum of the expected values for these sites. The amount accrued for the Company's remaining owned sites represents either costs resulting from feasibility studies or engineering estimates, the Company's share of a PRP allocation or, where no better estimate is available, the low end of a range of possible outcomes.

The majority of cost estimates for currently owned properties relate to the MGP sites, particularly the Harbor Point site (Utica, New York), which includes five surrounding non-owned sites. In October 1997, the Company submitted a draft feasibility study to the DEC for the Harbor Point and surrounding sites. The study indicates a range of viable remedial approaches. However, a final determination has not been made concerning the remedial approach to be taken. This range consists of a low end of $22 million and a high end of $230 million with an expected value calculation of $51 million, which is included in the total amounts accrued at December 31, 1997. The range represents the total costs to remediate Harbor Point and the surrounding sites and does not consider contributions from other PRPs. The Company anticipates receiving comments from the DEC on the draft feasibility study by the spring of 1999. At this time, the Company cannot definitively predict the nature of the DEC proposed remedial action plan or the range of remediation costs it will require. While the Company does not expect to be responsible for the entire cost to remediate these properties, it is not possible at this time to determine its share of the cost of remediation. In May 1995, the Company filed a complaint, pursuant to applicable Federal and New York State law, in the U.S. District Court for the Northern District of New York against several defendants seeking recovery of past and future costs associated with the investigation and remediation of the Harbor Point and surrounding sites. In a motion currently pending before the Court, the New York State Attorney General has moved to dismiss the Company's claims against the State of New York, the New York State Department of Transportation, the Thruway Authority and Canal Corporation. The Company has opposed this motion. The case management order presently calls for the close of discovery on December 31, 1998. As a result, the Company cannot predict the outcome of the pending litigation against other PRPs or the allocation of the Company's share of the costs to remediate the Harbor Point and surrounding sites.

With respect to sites not owned by the Company, but for which the Company has been or may be associated as a PRP, the Company has recorded a liability of $65 million, representing its best current estimate of its share of the total cost to investigate and remediate these sites. Total costs to investigate and remediate all non-owned sites is estimated to be approximately $285 million in the unlikely event the Company is required to assume 100% of the responsibility for these sites. The Company has denied any responsibility for certain of these PRP sites and is contesting liability accordingly. Eight of the PRP sites are included on the NPL. The Company estimates its share of the liability for these eight sites is not material and has included the amount in the determination of the amounts accrued.

Estimates of the Company's potential liability for sites not owned by the Company, but for which the Company has been identified as an alleged PRP, have been derived by estimating the total cost of site clean-up and then applying a Company contribution factor to that estimate where appropriate. Estimates of the total clean-up costs are determined by using all available information from investigations conducted by the Company and other parties, negotiations with other PRPs and, where no other basis is available at the time of estimate, the EPA figure for average cost to remediate a site listed on the NPL as disclosed in the Federal Register of June 23, 1993 (58 Fed. Reg. 119). A contribution factor is calculated, when there is a reasonable basis for it, that uses either a pro rata share based upon the total number of PRPs named or otherwise identified, or the percentage agreed upon with other PRPs through steering committee negotiations or by other means. In some instances, the Company has been unable to determine a contribution factor and has included in the amount accrued the total estimated costs to remediate the sites. Actual Company expenditures for these sites are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs as well as the financial viability of other PRPs since clean-up obligations are joint and several. While the Company has accrued an obligation of $220 million for its owned and non-owned sites, the high end of the range of remedial obligations is currently estimated to be approximately $650 million.

In May 1997, the DEC executed an Order on Consent (the "1997 Order") which serves to keep the annual cash requirement for certain site investigation and remediation ("SIR") level (at approximately $15 million per year), as well as provide for an annual site prioritization mechanism. As executed, the 1997 Order expands the scope of the original 1992 Order, which covered 21 former MGP sites, to encompass 52 sites with which the Company has been associated. The agreement is supported by the decision analysis approach, which the Company and the DEC will continue to revise on an annual basis to address SIR progress and site priorities relative to establishing the annual cost cap, as well as determining the Company's liability for these sites. The Saratoga Springs and Harbor Point MGP sites are being investigated and remediated pursuant to separate regulatory Consent Orders with the EPA and the DEC, respectively. However, the annual costs associated with the remediation of these sites are included in the cash requirements under the amended 1997 Order.

PowerChoice and the Company's gas settlement provide for the recovery of SIR costs over the settlement periods. The Company believes future costs, beyond the settlement periods, will continue to be recovered in rates. Based upon this assessment, a regulatory asset has been recorded in the amount of $220 million, representing the future recovery of remediation obligations accrued to date. As a result, the Company does not believe SIR costs will have a material adverse effect on its results of operations or financial condition. See also Part II, Item 8. Financial Statements and Supplementary Data - "Note 2. Rate and Regulatory Issues and Contingencies."

Where appropriate, the Company has provided notices of insurance claims to carriers with respect to the investigation and remediation costs for MGP, industrial waste sites and sites for which the Company has been identified as a PRP. To date, the Company has reached settlements with a number of insurance carriers, resulting in payments to the Company of approximately $36 million, net of costs incurred in pursuing recoveries. The Company has agreed, in its PowerChoice settlement, to amortize the portion allocated to the electric business, or approximately $32 million, over a ten-year period. The remaining portion relates to the gas business and is being amortized over the three-year settlement period.

For a discussion of additional environmental legal proceedings, see Item 3. Legal Proceedings.

RESEARCH AND DEVELOPMENT

The Company maintains a research and development ("R&D") program aimed at improving the delivery and use of energy products and finding practical applications for new and existing technologies in the energy business. These efforts include (1) improving efficiency; (2) minimizing environmental impacts; (3) improving facility availability; (4) minimizing maintenance costs; (5) promoting economic development and (6) improving the quality of life for our customers with new electric technologies. R&D expenditures in 1995 through 1997 were not material to the Company's results of operations or financial condition.

NUCLEAR OPERATIONS

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Other Federal and State Regulatory Initiatives - NRC and Nuclear Operating Matters" and Part II, Item 8. Financial Statements and Supplementary Data - "Note 3. Nuclear Operations."

CONSTRUCTION PROGRAM

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Financial Position, Liquidity and Capital Resources - Construction and Other Capital Requirements" and Part II, Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Construction Program."

ELECTRIC SUPPLY PLANNING

Under the PowerChoice agreement, the Company has agreed to put all of its fossil and hydro generation assets up for auction. Winning bids would be selected within 11 months of PSC approval of the auction plan, which was filed with the PSC on December 1, 1997 separately from the PowerChoice agreement. If the Company does not receive an acceptable positive bid for an asset, the Company agreed to form a subsidiary to hold any such assets and then to legally separate this subsidiary from the Company through a spin-off to shareholders or otherwise. After the foregoing process is complete, the Company agreed not to own any non-nuclear generating assets in the State of New York, subject to certain limited exceptions provided in the PowerChoice agreement.

ELECTRIC DELIVERY PLANNING

(See Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "FERC Rulemaking on Open Access and Stranded Cost Recovery.")

As of January 1, 1998, the Company had approximately 130,000 miles of transmission and distribution lines for electric delivery. Evaluation of these facilities relative to NYPP and Northeast Power Coordinating Council planning criteria and anticipated Company internal and external demands is an ongoing process intended to minimize the capital requirements for expansion of these facilities. (For a discussion of major restoration of the Company's electric delivery facilities in northern New York as a result of an ice storm in January 1998, see Part II, Item 8. Financial Statements and Supplementary Data - "Note 13. Subsequent Event)."

The Company has reviewed the adequacy of its electric delivery facilities and has determined that capital requirements to support new load growth will be below previous years' expenditures. Transmission planning studies are presently in progress to investigate the system impact of two proposed generation projects, U.S. Generating Company's 1080 MW plant located in Athens, New York and the Company's 723 MW repowering of the Albany Steam Station in Bethlehem, New York. (See Item 2. Properties -"Electric Service"). Both of these projects are filing for Article X certification with a projected in service date of 2001.

INSURANCE

As of January 31, 1998, the Company's directors and officers liability insurance was renewed. This coverage includes nuclear operations and insures the Company against obligations incurred as a result of its indemnification of directors and officers. The coverage also insures the directors and officers against liabilities for which they may not be indemnified by the Company, except for a dishonest act or breach of trust. In addition, for a discussion of nuclear insurance, see Part II, Item 8. Financial Statements and Supplementary Data - "Note 3. Nuclear Operations - Nuclear Liability Insurance" and - "Nuclear Property Insurance."

EMPLOYEE RELATIONS

The Company's work force at December 31, 1997 numbered approximately 8,500 of whom approximately 71% were union members. It is estimated that approximately 78% of the Company's total labor costs are applicable to operation and maintenance and approximately 22% are applicable to construction and other accounts.

All of the Company's non-supervisory production and clerical workers subject to collective bargaining are represented by the International Brotherhood of Electrical Workers ("IBEW"). In April 1996, the Company and the IBEW agreed on a five-year, three month labor agreement, which provides for wage increases of approximately 2% to 3% in each of the subsequent four years.

SEASONALITY

See Item 2. Properties - "Electric Service" and Part II, Item 8. Financial Statements and Supplementary Data - "Note 14. Quarterly Financial Data (Unaudited)."

Item 2. Properties.

ELECTRIC SERVICE

As of January 1, 1998, the Company owned and operated four fossil fuel steam plants (as well as having a 25% interest in the Roseton Steam Station and its output), two nuclear fuel steam plants, various diesel generating units and 72 hydroelectric plants, and had a majority interest in Beebee Island and Feeder Dam hydro plants and their output. The Company also purchases substantially all of the output of 93 other hydroelectric facilities. The Company's wholly-owned subsidiary, Opinac North America, Inc., owns Opinac Energy Corporation and Plum Street Enterprises, Inc. Opinac Energy Corporation has a 50 percent interest in CNP (owner and operator of the 76.8 MW Rankine hydroelectric plant) which distributes electric power within the Province of Ontario and owns a windmill generator in the Province of Alberta. In addition, the Company has contracts to purchase electric energy from NYPA and other sources. See Item 1. Business - "IPPs," - "New York Power Authority" and - "Other Purchased Power" and Part II, Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Long-term Contracts for the Purchase of Electric Power" and - "Electric and Gas Statistics." The Company holds the FERC license for 65 hydroelectric plants. A significant number of these licenses are subject to renewal over the next 4 years. As of December 31, 1997, the Company has renewed 2 hydro licenses and has 7 license renewals pending. In the event the Company is unable to renew a hydro license, it is entitled to compensation for the facility. (See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement - PowerChoice Agreement" for a discussion of the Company's plans to sell its fossil and hydro assets).

The following is a list of the Company's major operating generating stations at February 1, 1998:

Station, Location and Percent Ownership	Energy Source	Company's Share of Nominal Net Capability in MW
Huntley, Niagara River (100%)	Coal	760
Dunkirk, Lake Erie (100%)	Coal	600
Albany, Hudson River (100%)	Oil/Natural Gas	400
Oswego, Lake Ontario (76%) (Unit 6)	Oil/Natural Gas	646
Roseton, Hudson River (25%)	Oil/Natural Gas	300
Nine Mile Point, Lake Ontario (100%) (Unit 1)	Nuclear	613
Nine Mile Point, Lake Ontario (41%) (Unit 2)	Nuclear	469

In 1994, Oswego Unit No. 5 (an oil-fired unit with a net book value of $160 million and a capability of 850 MW) was put into long-term cold standby, but can be returned to service in three months.

The Company is pursuing the necessary permits to install state-of-the-art technology at the Albany Steam Station to redevelop the facility to increase the capacity from the current 400 MW to 723 MW and rename the station the Bethlehem Energy Center. The new facility would use natural gas fueled combined cycle units which would reduce air emissions and significantly improve the facility's operating efficiency. The licensing effort and permitting process is expected to take up to 18 months and be transferable to a new owner of the facility under the fossil and hydro generating facility auction.

The electric system of the Company and CNP is directly interconnected with other electric utility systems in Ontario, Quebec, New York, Massachusetts, Vermont and Pennsylvania, and indirectly interconnected with most of the electric utility systems through the Eastern Interconnection of the United States. As of December 31, 1997, the Company's electric transmission and distribution systems were composed of 952 substations with a rated transformer capacity of approximately 28,500,000 kilovoltamperes, approximately 8,000 circuit miles of overhead transmission lines, approximately 1,100 cable miles of underground transmission lines, approximately 113,100 conductor miles of overhead distribution lines and about 5,800 cable miles of underground distribution cables, only a part of such transmission and distribution lines being located on property owned by the Company.

There is seasonal variation in electric customer load. In 1997, the Company's maximum hourly demand occurred in the summer. Historically, the Company's maximum hourly demand occurred in the winter. The maximum simultaneous hourly demand (excluding economy and emergency sales to other utilities) on the electric system of the Company for the twelve months ended December 31, 1997 occurred on July 15, 1997 and was 6,348,000 KWh. For a summary of the Company's electric supply capability at December 31, 1997, see Part II, Item 8. Financial Statements and Supplementary Data - "Electric and Gas Statistics."

The Company owns and operates several electric transmission lines crossing the Seneca Nation Cattaraugus and Allegany Reservations which range from 230 kilovolts to 34.5 kilovolts. In 1991, the Seneca Nation challenged the validity of the right-of-way agreements for these transmission lines. While discussions between the Nation and the Company were suspended in mid-1992, the Nation has recently asked the Company to reopen the discussions. The Company is unable to estimate any potential costs associated with this issue, if any.

NEW YORK POWER POOL

The Company, six other New York utilities and NYPA constitute the NYPP, through which they coordinate the planning and operation of their interconnected electric production and transmission facilities in order to improve reliability of service and efficiency for the benefit of customers of their respective electric systems. For a discussion on potential changes to NYPP, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement" and - "FERC Rulemaking on Open Access and Stranded Cost Recovery."

GAS SERVICE

The Company distributes gas purchased from suppliers and transports gas owned by others. As of December 31, 1997, the Company's natural gas system was comprised of approximately 8,000 miles of pipelines and mains, only a part of which is located on property owned by the Company.

SUBSIDIARIES

One of the Company's wholly-owned subsidiaries, Opinac North America, Inc. owns Opinac Energy Corporation (a Canadian corporation) and Plum Street Enterprises, Inc. Opinac Energy Corporation has a 50 percent interest in an electric company, CNP, which has operations in the Province of Ontario, Canada. CNP generates electricity at its Rankine hydro plant for the wholesale market and for its distribution system in Fort Erie, Ontario. CNP owns a 99.99% interest in Canadian Niagara Wind Power Company, Inc. and Cowley Ridge Partnership, respectively, which together operate a wind power joint venture in the Province of Alberta, Canada. Plum Street Enterprises, Inc., incorporated in the State of Delaware, is an unregulated company that offers energy related services. A wholly-owned Texas subsidiary of the Company, NM Uranium, Inc. has an interest in a uranium mining operation in Live Oak County, Texas which is now in the process of reclamation and restoration. Another wholly-owned New York State subsidiary of the Company, NM Holdings, Inc., engages in real estate development of property formerly owned by the utility company. In addition, the Company has established a single-purpose wholly-owned subsidiary, NM Receivables Corporation, to facilitate its sale of an undivided interest in a designated pool of customer receivables, including accrued unbilled revenues. The Company also owns a 66.67 percent and 82.84 percent interest in Moreau Manufacturing Corporation and Beebee Island Corporation, respectively, which are New York State subsidiaries that own and operate hydro-electric generating stations.

MORTGAGE LIENS

Substantially all of the Company's operating properties are subject to a mortgage lien securing its mortgage debt. (See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the Revised PowerChoice Agreement").

Item 3. Legal Proceedings.

For a detailed discussion of additional legal proceedings, see Part II, Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Tax Assessments" and - "Environmental Contingencies." See also Item 1. Business - "Environmental Matters - Solid/Hazardous Waste," and Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement." The Company is unable to predict the ultimate disposition of the matters referred to below in (1), (2), (3), (4) and (5). However, the Company has previously been allowed to recover these types of expenditures in rates. In addition, consistent with PowerChoice, the Company believes that it is probable that the Company will continue to recover these types of expenditures in cost-of-service based rates. See also Part II, Item 8. Financial Statements and Supplementary Data - "Note 2. Rate and Regulatory Issues and Contingencies."

1. On June 22, 1993, the Company and twenty other industrial entities, as well as the owner/operator of the Pfohl Brothers Landfill near Buffalo, New York, were sued in NYS Supreme Court, Erie County, by a group of residents living in the area surrounding the landfill. The plaintiffs seek compensation for alleged economic loss and property damage claimed to have resulted from exposure to contamination associated with the landfill. In addition, since January 18, 1995, the Company has been named as a defendant or third-party defendant in a series of toxic tort actions filed in federal or state courts in the Buffalo area. These actions allege exposure on the part of plaintiffs or plaintiffs' decedents to toxic chemicals emanated from the landfill, resulting in the alleged causation of cancer. The plaintiffs seek compensatory and punitive damages so far totalling approximately $60 million. The Company has filed answers responding to the claims put forth in these suits, denying liability as to any of the claimed conditions or damages, and intends to continue to vigorously defend against each claim.

   The Company is unable to predict at this time the probable outcome of these proceedings, which at present remain in the discovery stage. The Company, through membership in the Pfohl Brothers landfill Site Committee, is participating in the design and implementation of a remedial program for the landfill. In the context of liability allocation procedures conducted on behalf of the Committee, it has been determined that the Company's contribution of industrial wastes to the landfill was minor. Further, it is the Company's position that materials present at the landfill attributable to the Company are not causally related to any condition alleged by plaintiffs in the various lawsuits associated with the landfill. The Company does not believe that the outcome of these proceedings will have a material adverse effect on its results of operations or financial condition.

2. On October 23, 1992, the Company petitioned the PSC to order IPPs to post letters of credit or other firm security to protect ratepayers' interests in advance payments made in prior years to these generators. The PSC dismissed the original petition without prejudice. In December 1995, the Company filed a petition with the PSC similar to the one that the Company filed in October 1992. The Company cannot predict the outcome of this action. However, in August 1996, the PSC proposed to examine the circumstances under which a utility, including the Company, should be allowed to demand security from IPPs to ensure the repayment of advance payments made under their purchased power contracts. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Other Federal and State Regulatory Initiatives - PSC Proposal of New IPP Operating and PPA Management Procedures."

   On February 4, 1994, the Company notified the owners of nine projects with contracts that provide for front-end loaded payments of the Company's demand for adequate assurance that the owners will perform all of their future repayment obligations, including the obligation to deliver electricity in the future at prices below the Company's avoided cost as required by agreements and the repayment of any advance payment which remains outstanding at the end of the contract. The projects at issue total 426 MW. The Company's demand is based on its assessment of the amount of advance payment to be accumulated under the terms of the contracts, future avoided costs and future operating costs for the projects. Litigation ensued with six of the projects as a result of these notifications, as follows:

On March 4, 1994, Encogen Four Partners, L.P. ("Encogen") filed a complaint in the United States District Court for the Southern District of New York (the "U.S. District Court") alleging breach of contract and prima facie tort by the Company. Encogen seeks compensatory damages of approximately $1 million and unspecified punitive damages. In addition, Encogen seeks a declaratory judgment that the Company is not entitled to assurance of future performance from Encogen. On April 4, 1994, the Company filed its answer and counterclaim for declaratory judgment relating to the Company's exercise of its right to demand adequate assurance. Encogen has amended its complaint, rescinded its prima facie tort claim, and filed a motion of judgment on the pleadings. On February 6, 1996, the U.S. District Court granted Encogen's motion for judgment on the pleadings and ruled that under New York law, the Company did not have the right to demand adequate assurances of future performance. In addition, the U.S. District Court did not award any damages. The Company has appealed this decision. A motion to stay further proceedings has been made since this contract is included in the MRA.

On March 4, 1994, Sterling Power Partners, L.P. ("Sterling"), Seneca Power Partners, L.P., Power City Partners, L.P. and AG-Energy, L.P. filed a complaint in the NYS Supreme Court seeking a declaratory judgment that: (a) the Company does not have any legal right to demand assurance of plaintiffs' future performance; (b) even if such a right existed, the Company lacks reasonable insecurity as to plaintiffs' future performance; (c) the specific forms of assurances sought by the Company are unreasonable and (d) if the Company is entitled to any form of assurances, plaintiffs have provided adequate assurances. On April 4, 1994, the Company filed its answer and counterclaim for declaratory judgment relating to the Company's exercise of its right to demand adequate assurance. On October 5, 1994, Sterling moved for summary judgment and the Company opposed and cross moved for summary judgment. On February 16, 1996, Sterling supplemented its motion, claiming that the February 6, 1996 ruling in the Encogen case is dispositive. On February 29, 1996, the NYS Supreme Court granted Sterling's motion for summary judgment and ruled that under New York law, the Company did not have the right to demand adequate assurances of future performance. The Company has appealed this decision. A motion to stay further proceedings has been made since this contract is included in the MRA.

On March 7, 1994, NorCon Power Partners, L.P. ("NorCon") filed a complaint in the U.S. District Court seeking to enjoin the Company from terminating a PPA between the parties and seeking a declaratory judgment that the Company has no right to demand additional security or other assurances of NorCon's future performance under the PPA. NorCon sought a temporary restraining order against the Company to prevent the Company from taking any action on its February 4, 1994 letter. On March 14, 1994, the Court entered the interim relief sought by NorCon. On April 4, 1994, the Company filed its answer and counterclaim for declaratory judgment relating to the Company's exercise of its right to demand adequate assurance. On November 2, 1994, NorCon filed for summary judgment. On February 6, 1996, the U.S. District Court granted NorCon's motion for summary judgment and ruled that under New York law, the Company did not have the right to demand adequate assurances of future performance. On March 25, 1997, the U.S. Court of Appeals for the Second Circuit ordered that the question of whether there exists under New York commercial law the right to demand firm security on an electric contract should be certified to the N.Y. Court of Appeals, the highest New York court, for final resolution. The Second Circuit order effectively stayed the U.S. District Court's order against the Company, pending final disposition by the N.Y. Court of Appeals. A motion to stay further proceedings has been made since this contract is included in the MRA.

The Company can neither provide any judgement regarding the likely outcome nor any estimate or range of possible loss or reduction of exposure in the cases above. Accordingly, no provision for liability, if any, that may result from any of these suits has been made in the Company's financial statements. If the MRA closes with respect to the

IPP Parties mentioned above, then these litigations would be dismissed with respect to such IPP Parties (see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement").

3. In November 1993, Fourth Branch Associates Mechanicville ("Fourth Branch") filed an action against the Company and several of its officers and employees in the NYS Supreme Court, seeking compensatory damages of $50 million, punitive damages of $100 million and injunctive and other related relief. The lawsuit grows out of the Company's termination of a contract for Fourth Branch to operate and maintain a hydroelectric plant the Company owns in the Town of Halfmoon, New York. Fourth Branch's complaint also alleges claims based on the inability of Fourth Branch and the Company to agree on terms for the purchase of power from a new facility that Fourth Branch hoped to construct at the Mechanicville site. In January 1994, the Company filed a motion to dismiss Fourth Branch's complaint. By order dated November 7, 1995, the Court granted the Company's motion to dismiss the complaint in its entirety. Fourth Branch filed an appeal from the Court's order. On January 30, 1997, the Appellate Division modified the November 7, 1995 court decision by reversing the dismissal of the fourth and fifth causes of action set forth in Fourth Branch's complaint.

   The Company and Fourth Branch had also entered into negotiations under a FERC mediation process. As a result of these negotiations, the Company had proposed to sell the hydroelectric plant to Fourth Branch for an amount which would not be material. In addition, the proposal included a provision that would require the discontinuance of all litigation between the parties.

   Attempts to implement this proposal have been unsuccessful and the Company has informed FERC that its participation in the mediation efforts has been concluded. On January 14, 1997, the FERC Administrative Law Judge issued a report to FERC recommending that the mediation proceeding be terminated, leaving outstanding a Fourth Branch complaint to FERC that alleges anti-competitive conduct by the Company. The Company has made a motion to dismiss Fourth Branch's antitrust complaint before the FERC, which motion was opposed by Fourth Branch. A decision from FERC on this matter is pending.

   The Company is unable to predict the ultimate disposition of the lawsuit referred to above. However, the Company believes it has meritorious defenses and intends to defend this lawsuit vigorously. No provision for liability, if any, that may result from this lawsuit has been made in the Company's financial statements.

4. In March 1993, Inter-Power of New York, Inc. ("Inter-Power") filed a complaint against the Company and certain of its officers and employees in the NYS Supreme Court. Inter-Power alleged, among other matters, fraud, negligent misrepresentation and breach of contract in connection with the Company's alleged termination of a PPA in January 1993. The plaintiff sought enforcement of the original contract or compensatory and punitive damages in an aggregate amount that would not exceed $1 billion, excluding pre-judgment interest.

   In early 1994, the NYS Supreme Court dismissed two of the plaintiff's claims; this dismissal was upheld by the Appellate Division, Third Department of the NYS Supreme Court. Subsequently, the NYS Supreme Court granted the Company's motion for summary judgment on the remaining causes of action in Inter-Power's complaint. In August 1994, Inter-Power appealed this decision and on July 27, 1995, the Appellate Division, Third Department affirmed the granting of summary judgment as to all counts, except for one dealing with an alleged breach of the PPA relating to the Company's having declared the agreement null and void on the grounds that Inter-Power had failed to provide it with information regarding its fuel supply in a timely fashion. This one breach of contract claim was remanded to the NYS Supreme Court for further consideration. In January 1998, the NYS Supreme Court granted the Company's motion for summary judgment on all remaining claims in this lawsuit and dismissed this lawsuit in its entirety. In January 1998, Inter-Power filed a notice of appeal.

5. The DEC, in response to an EPA audit of their enforcement policies, which found enforcement of air regulation violations to be insufficient, has begun an initiative to address this issue. As a result, the DEC is seeking penalties from all New York utilities for past opacity variances for the years 1994, 1995 and 1996. Furthermore, the DEC is requiring various opacity reduction measures and stipulated penalties for future excursions after execution of a consent order. All New York State utilities, including the Company, which was notified in September 1997, are in the process of negotiating the various terms and conditions of the draft consent order with the DEC. The outcome of this matter is uncertain at this time and it is not possible to predict what the financial impact to the Company will be in terms of penalty payment and implementation of an opacity reduction program.

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

On October 23, 1997, the Board of Directors authorized the solicitation of consents from its preferred shareholders, as required by the Company's Certificate of Incorporation, to increase the amount of unsecured debt the Company may issue from the level prior to the consent of approximately $700 million by up to an additional $5 billion. On December 3, 1997, the preferred shareholders approved the proposal to increase the level of unsecured debt by a vote of 3,562,645 for, 479,124 against and 140,107 abstentions.

Executive Officers of Registrant

All executive officers of the Company are elected on an annual basis at the May meeting of the Board of Directors or upon the filling of a vacancy. There are no family relationships between any of the executive officers. There are no arrangements or understandings between any of the officers listed below and any other person pursuant to which he or she was selected as an officer.

Executive	Age at 12/31/97	Current and Prior Positions	Date Commenced
William E. Davis	55	Chairman of the Board and Chief Executive Officer	May 1993
		Vice Chairman of the Board of Directors	November 1992
Albert J. Budney, Jr.	50	President	April 1995
		Managing Vice President - UtiliCorp Power Services Group (a unit of Utilicorp United, Inc.)	Prior to Joining the Company
		President-Missouri Public Service (Operating Division of UtiliCorp United, Inc.)	January 1993
B. Ralph Sylvia	57	Executive Vice President	January 1998*
		Executive Vice President - Electric Generation and Chief Nuclear Officer	December 1995
		Executive Vice President - Nuclear	November 1990
David J. Arrington	46	Senior Vice President - Human Resources	December 1990
William F. Edwards	40	Senior Vice President and Chief Financial Officer	September 1997
		Vice President - Financial Planning	December 1995
		Executive Assistant to the Chief Executive Officer and President	July 1993
		Director of Budget and Financial Management	June 1989
Darlene D. Kerr	46	Senior Vice President - Energy Distribution	December 1995
		Senior Vice President - Electric Customer Service	January 1994
		Vice President - Electric Customer Service	July 1993
		Vice President - Gas Marketing and Rates	February 1991
Gary J. Lavine	47	Senior Vice President - Legal & Corporate Relations	May 1993
		Senior Vice President - Legal & Corporate Relations and General Counsel	October 1992
John H. Mueller	51	Senior Vice President and Chief Nuclear Officer	January 1998*
		Site Vice President of Commonwealth Edison's Zion Plant	August 1996
		Vice President of Nuclear Energy (for the Nebraska Public Power District, owner and operator of the Cooper nuclear plant)	July 1994
		Plant Manager - Unit 2	August 1993
		Operations Manager - Unit 2	October 1992
John W. Powers	59	Retired	December 1997
		Senior Vice President	September 1997
		Senior Vice President and Chief Financial Officer	January 1996
		Senior Vice President - Finance & Corporate Services	October 1990
Theresa A. Flaim	48	Vice President - Corporate Strategic Planning	May 1994
		Vice President - Corporate Planning	April 1993
		Manager - Gas Rates & Integrated Resource Planning	June 1991
Kapua A. Rice	46	Corporate Secretary	September 1994
		Assistant Secretary	October 1992
		Manager - Legal & Corporate Relations	July 1991
Steven W. Tasker	40	Vice President - Controller	December 1993
		Controller	May 1991

* On January 13, 1998, John H. Mueller was elected as Senior Vice President and Chief Nuclear Officer, which became effective January 19, 1998. He will succeed B. Ralph Sylvia, who will remain with the Company as an Executive Vice President until his planned mid-year retirement.

PART II

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

The Company's common stock and certain of its preferred series are listed on the New York Stock Exchange ("NYSE"). The common stock is also traded on the Boston, Cincinnati, Midwest, Pacific and Philadelphia stock exchanges. Common stock options are traded on the American Stock Exchange. The ticker symbol is "NMK."

Preferred dividends were paid on March 31, June 30, September 30 and December 31. The Company estimates that none of the 1997 preferred stock dividends will constitute a return of capital and therefore all of such dividends are subject to Federal tax as ordinary income.

The table below shows quoted market prices (NYSE) for the Company's common stock:

	1997		1996	
	High	Low	High	Low
1st Quarter	$11 1/8	$8 1/8	$10 1/8	$6 1/2
2nd Quarter	9	7 7/8	8 5/8	6 1/2
3rd Quarter	10 1/16	8 1/4	8 7/8	6 3/4
4th Quarter	10 9/16	9 1/16	10	7 5/8

For a discussion regarding the common stock dividend, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Accounting Implications of the PowerChoice Agreement and Master Restructuring Agreement" and "Financial Position, Liquidity and Capital Resources - Common Stock Dividend" below.

Other Stockholder Matters. The holders of common stock are entitled to one vote per share and may not cumulate their votes for the election of Directors. Whenever dividends on preferred stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such preferred stock can elect a majority of the Board of Directors. Whenever dividends on any preference stock are in default in an amount equivalent to six full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such stock can elect two members to the Board of Directors. No dividends on preferred stock are now in arrears and no preference stock is now outstanding. Upon any dissolution, liquidation or winding up of the Company's business, the holders of common stock are entitled to receive a pro rata share of all of the Company's assets remaining and available for distribution after the full amounts to which holders of preferred and preference stock are entitled have been satisfied.

Upon consummation of the MRA (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement" for a listing of conditions that must be met in order to close the MRA), which is expected to occur later this year, the IPP Parties are expected to own 42.9 million shares of the Company's common stock, representing 23% of the Company's voting securities following the issuance of such shares. In the MRA, the parties agree that any IPP Party that receives 2% or more of the outstanding Common Stock and any designees of IPP Parties that receives more than 4.9% of the outstanding Common Stock upon the consummation of the MRA will, together with certain but not all affiliates (collectively, "2% Shareholders"), enter into certain shareholder agreements (the "Shareholders Agreements"). Pursuant to each Shareholder Agreement, the 2% Shareholders agree that for five years they will not acquire more than an additional 5% of the outstanding Common Stock (resulting in ownership in all cases of no more than 9.9%) or take any actions to attempt to acquire control of the Company, other than certain permitted actions in response to unsolicited actions by third parties. The 2% shareholders will generally vote their shares on a "pass-through" basis, that is in the same proportion as all shares held by other shareholders are voted, except that they may vote in their discretion for extraordinary transactions and, when there is a pending proposal to acquire the Company, for directors.

The indenture securing the Company's mortgage debt provides that retained earnings shall be reserved and held unavailable for the payment of dividends on common stock to the extent that expenditures for maintenance and repairs plus provisions for depreciation do not exceed 2.25% of depreciable property as defined therein. Such provisions have never resulted in a restriction of the Company's retained earnings.

As of March 26, 1998, there were approximately 66,300 holders of record of common stock of the Company and about 4,700 holders of record of preferred stock. The chart below summarizes common stockholder ownership by size of holding:

Size of Holding (Shares)	Total Stockholders	Total Shares Held
1 to 99	31,056	812,652
100 to 999	31,930	7,775,973
1,000 or more	3,325	135,830,726
	66,311	144,419,351

Item 6. Selected Consolidated Financial Data

The following table sets forth selected financial information of the Company for each of the five years during the period ended December 31, 1997, which has been derived from the audited financial statements of the Company, and should be read in connection therewith. As discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data - "Notes to Consolidated Financial Statements," the following selected financial data is not likely to be indicative of the Company's future financial condition or results of operations.

	1997	1996*	1995	1994	1993
Operations: (000's)					
Operating revenues	$3,966,404	$3,990,653	$3,917,338	$4,152,178	$3,933,431
Net income	59,835	110,390	248,036	176,984	271,831
Common stock data:					
Book value per share at year end	$18.03	$17.91	$17.42	$17.06	$17.25
Market price at year end	10 1/2	9 7/8	9 1/2	14 1/4	20 1/4
Ratio of market price to book value at year end	58.2%	55.1%	54.5%	83.5%	117.4%
Dividend yield at year end	-	-	11.8%	7.9%	4.9%
Basic and diluted earnings per average common share	$.16	$ .50	$1.44	$1.00	$1.71
Rate of return on common equity	0.9%	2.8%	8.4%	5.8%	10.2%
Dividends paid per common share	-	-	$1.12	$1.09	$ .95
Dividend payout ratio	-	-	77.8%	109.0%	55.6%
Capitalization: (000's)					
Common equity	$2,604,027	$2,585,572	$2,513,952	$2,462,398	$2,456,465
Non-redeemable preferred stock	440,000	440,000	440,000	440,000	290,000
Mandatorily redeemable preferred stock	76,610	86,730	96,850	106,000	123,200
Long-term debt	3,417,381	3,477,879	3,582,414	3,297,874	3,258,612
Total	6,538,018	6,590,181	6,633,216	6,306,272	6,128,277
[illegible]term debt maturing within one year	67,095	48,084	65,064	77,971	216,185
[illegible]l	$6,605,113	$6,638,265	$6,698,280	$6,384,243	$6,344,462
Capitalization ratios: (including long-term debt maturing within one year):					
Common stock equity	39.4%	39.0%	37.5%	38.6%	38.7%
Preferred stock	7.8	7.9	8.0	8.5	6.5
Long-term debt	52.8	53.1	54.5	52.9	54.8
Financial ratios:					
Ratio of earnings to fixed charges	1.39	1.57	2.29	1.91	2.31
Ratio of earnings to fixed charges and preferred stock dividends	1.12	1.31	1.90	1.63	2.00
Other ratios-% of operating revenues:					
Fuel, electricity purchased and gas purchased	44.4%	43.5%	40.3%	39.6%	36.1%
Other operation and maintenance expenses	21.1	23.3	20.9	23.1	26.9
Depreciation and amortization	8.6	8.3	8.1	7.4	7.0
Federal and foreign income taxes, and other taxes	13.4	13.6	17.3	14.7	16.2
Operating income	14.1	13.1	17.5	13.3	17.5
Balance available for common stock	0.6	1.8	5.3	3.5	6.1
Miscellaneous: (000's)					
Gross additions to utility plant	$ 290,757	$ 352,049	$ 345,804	$ 490,124	$ 519,612
Total utility plant	11,075,874	10,839,341	10,649,301	10,485,339	10,108,529
Accumulated depreciation and amortization	4,207,830	3,881,726	3,641,448	3,449,696	3,231,237
[illegible]ssets	9,584,141	9,427,635	9,477,869	9,649,816	9,471,327

*Amounts include extraordinary item, see Note 2. Rate and Regulatory Issues and Contingencies.

Certain statements included in this Annual Report on Form 10-K are forward-looking statements as defined in Section 21E of the Securities Exchange Act of 1934, including the hedge against upward movement in market prices provided by the restructured and amended PPAs, the improvement in operating cash flows as a result of the MRA and PowerChoice, the recoverability of the MRA regulatory asset through the prices charged for electric service, the effect of a PSC natural gas proposal on the Company's results of operations, expected earnings over the five-year term of the PowerChoice agreement, the effect of the elimination of the FAC under PowerChoice on the Company's financial condition, the reduction in net income resulting from the non-cash amortization of the MRA regulatory asset, the effect of the January 1998 ice storm damage restoration costs on the Company's capital requirements, recoverability of environmental compliance costs and nuclear decommissioning costs through rates, and the improvement in the Company's financial condition expected as a result of the MRA and the implementation of PowerChoice. The Company's actual results and developments may differ materially from the results discussed in or implied by such forward-looking statements, due to risks and uncertainties that exist in the Company's operations and business environment, including, but not limited to, matters described in the context of such forward-looking statements, as well as such other factors as set forth in the Notes to Consolidated Financial Statements contained herein.

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

EVENTS AFFECTING 1997 AND THE FUTURE

- On July 9, 1997, the Company announced the MRA to terminate, restate or amend IPP power purchase contracts in exchange for cash, shares of the Company's common stock and certain financial contracts. The terms of the MRA have been and may continue to be modified.
- In February 1998, the PSC approved the PowerChoice settlement agreement, which incorporates the terms of the MRA. Under PowerChoice, a regulatory asset will be established for the costs of the MRA and it will be amortized over a period not to exceed ten years. The Company's rates under PowerChoice are designed to permit recovery of the MRA regulatory asset. In approving PowerChoice, the PSC limited the estimated value of the MRA regulatory asset that can be recovered to approximately $4,000 million, resulting in a charge to 1997 earnings of $190.0 million or 85 cents per share. The PowerChoice agreement, while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.
- In December 1997, the preferred shareholders gave the Company approval to increase the amount of unsecured debt that the Company may issue by $5 billion. This authorization enables the issuance of unsecured debt to consummate the MRA.
- The PowerChoice agreement calls for the Company to conduct an auction to sell all of its fossil and hydro generation assets.
- In early January 1998, a major ice storm caused extensive and costly damage to the Company's facilities in northern New York.

MASTER RESTRUCTURING AGREEMENT AND THE POWERCHOICE AGREEMENT

The Company entered into the PPAs that are subject to the MRA because it was required to do so under PURPA, which was intended to provide incentives for businesses to create alternative energy sources. Under PURPA, the Company was required to purchase electricity generated by qualifying facilities of IPPs at prices that were not expected to exceed the cost that otherwise would have been incurred by the Company in generating its own electricity, or in purchasing it from other sources (known as "avoided costs"). While PURPA was a federal initiative, each state retained certain delegated authority over how PURPA would be implemented within its borders. In its implementation of PURPA, the State of

New York passed the "Six-Cent Law," establishing 6¢ per KWh as the floor on avoided costs for projects less than 80 MW in size. The Six-Cent Law remained in place until it was amended in 1992 to deny the benefit of the statute to any future PPAs. The avoided cost determinations under PURPA were periodically increased by the PSC during this period. PURPA and the Six-Cent Law, in combination with other factors, attracted large numbers of IPPs to New York State, and, in particular, to the Company's service territory, due to the area's existing energy infrastructure and availability of cogeneration hosts. The pricing terms of substantially all of the PPAs that the Company entered into in compliance with PURPA and the Six-Cent Law or other New York laws were based, at the option of the IPP, either on administratively determined avoided costs or minimum prices, both of which have consistently been materially higher than the wholesale market prices for electricity.

Since PURPA and the Six-Cent Law were passed, the Company has been required to purchase electricity from IPPs in quantities in excess of its own demand and at prices in excess of that available to the Company by internal generation or for purchase in the wholesale market. In fact, by 1991, the Company was facing a potential obligation to purchase power from IPPs substantially in excess of its peak demand of 6,093 MW. As a result, the Company's competitive position and financial performance have deteriorated and the price of electricity paid per KWh by its customers has risen significantly above the national average. Accordingly, in 1991 the Company initiated a parallel strategy of negotiating individual PPA buyouts, cancellations and renegotiations, and of pursuing regulatory and legislative support and litigation to mitigate the Company's obligation under the PPAs. By mid-1996, this strategy had resulted in reducing the capacity of the Company's obligations to purchase power under its PPA portfolio to approximately 2,700 MW. Notwithstanding this reduction in capacity, over the same period the payments made to the IPPs under their PPAs rose from approximately $200 million in 1990 to approximately $1.1 billion in 1997 as independent power facilities from which the Company was obligated to purchase electricity commenced operations. The Company estimates that absent the MRA, payments made to the IPPs pursuant to PPAs would continue to escalate by approximately $50 million per year until 2002.

Recognizing the competitive trends in the electric utility industry and the impracticability of remedying the situation through a series of customer rate increases, in mid-1996 the Company began comprehensive negotiations to terminate, amend or restate a substantial portion of above-market PPAs in an effort to mitigate the escalating cost of these PPAs as well as to prepare the Company for a more competitive environment. These negotiations led to the MRA and the PowerChoice agreement.

Master Restructuring Agreement. On July 9, 1997, the Company entered into the MRA with 16 IPP Parties who sell electricity to the Company under 29 PPAs. The MRA specifically contemplated that two IPPs, Oxbow Power of North Tonawanda, New York, Inc. ("Oxbow") and NorCon would enter into further negotiations concerning their treatment under the MRA. Following such negotiations, Oxbow has withdrawn from the MRA, but, based on the value of its allocation under the MRA and the terms of its existing PPA, Oxbow's withdrawal does not materially impact the cost reductions associated with the MRA. The Company and NorCon have agreed to replace NorCon's initial allocation under the MRA with an all cash allocation which has, in the Company's estimation, a value approximately $60 million higher than NorCon's initial allocation. A third IPP Party has agreed to take cash in exchange for the shares of common stock allocated to it in the MRA. As a result of these cash allocations, there are 3,054,000 fewer shares of common stock allocated to the IPPs under the MRA. The MRA has been amended to expire on July 15, 1998.

The MRA currently provides for the termination, restatement or amendment of 28 PPAs with 15 IPPs, which represent approximately 80% of the Company's over-market purchased power obligations, in exchange for an aggregate of $3,616 million in cash and 42.9 million shares of the Company's common stock and certain financial contracts. The closing of the MRA is subject to a number of conditions, including the Company and the IPP Parties negotiating individual restated and amended contracts, the receipt of all regulatory approvals, the receipt of all consents by third parties necessary for the transactions contemplated by the MRA (including the termination of the existing PPAs and the termination or amendment of all related third party agreements), the IPP Parties entering into new third party arrangements which will enable each IPP Party to restructure its projects on a reasonably satisfactory economic basis, the Company having completed all necessary financing arrangements and the Company and the IPP Parties having received all necessary approvals from their respective boards of directors, shareholders and partners. While one or more of the IPP Parties may under certain circumstances terminate the MRA with respect to itself, the Company's obligation to close the MRA is subject to its determination that as a result of any such terminations the benefits anticipated to be received by the Company pursuant to the MRA have not been materially and adversely affected. The Company expects that prior to the consummation of the MRA, the mix of consideration to be received by the IPP Parties may be renegotiated. The foregoing is qualified in its entirety by the text of the MRA (see Exhibit 10-11). As the Conditions Determination Date (the date by which all IPP Parties must satisfy or waive their third party conditions or withddraw from the MRA) has not occurred, the Company cannot predict whether such conditions will be satisfied, whether some IPP Parties may withdraw, whether the terms of the MRA might be renegotiated, or whether the MRA will be consummated. In the event the Company is unable to successfully complete the MRA and therefore implement PowerChoice, it would pursue all alternatives including a traditional rate request.

The principal effects of the MRA are to reduce significantly the Company's existing payment obligations under the PPAs, which currently consist of approximately 2,700 MW of capacity at December 31, 1997. While earnings will be depressed during the five-year term, the savings in annual energy payments, coupled with the rates established in PowerChoice, will yield free cash flow that can be dedicated to the new debt service obligations associated with the payment of cash to the IPP Parties.

Under the terms of the MRA, the Company's significant long term and escalating IPP payment obligations will be restructured into a defined and more manageable obligation and a portfolio of restated and amended PPAs with price and duration terms that the Company believes are more favorable than the existing PPAs. Under the MRA, 19 PPAs representing approximately 1,180 MW of capacity will be terminated completely thus allowing this capacity to be replaced through the competitive market at market based prices. The Company has no continuing obligation to purchase energy from the terminating IPP Parties.

Also under the MRA, 8 PPAs representing approximately 541 MW of capacity will be restated on economic terms and conditions that are more favorable to the Company than the existing PPAs. The restated contracts have a term of 10 years and are structured as financial swap contracts where the Company receives or makes payments to the IPP Parties based upon the differential between the contract price and a market reference price for electricity. The contract prices are fixed for the first two years changing to an indexed pricing formula thereafter. Contract quantities are fixed for the full 10 year term of the contracts. The indexed pricing structure ensures that the price paid for energy and capacity will fluctuate relative to the underlying market cost of gas and general indices of inflation. Until such time as a competitive energy market structure becomes operational in the State of New York, the restated contracts provide the IPP Parties with a put option for the physical delivery of energy. Additionally, one PPA representing 42 MW of capacity will be amended to reflect a shortened term and a lower stream of fixed unit prices. Finally, the MRA requires the Company to provide the IPP Parties with a number of fixed price swap contracts with a term of seven years beginning in 2003. The fixed price swap contracts will be cash settled monthly based upon a stream of defined quantities and prices.

Although against the Company's forecast of market energy prices the restructured and amended PPAs represent an expected above-market payment obligation, the Company's portfolio of these PPAs provides it and its customers with a hedge against significant upward movement in market prices that may be caused by a change in energy supply or demand. This portfolio and market purchases contain terms that are believed to be more responsive to competitive market price changes. (See Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Long-term Contracts for the Purchase of Electric Power").

PowerChoice Agreement. The PowerChoice agreement establishes a five-year rate plan that will reduce average residential and commercial rates by an aggregate of 3.2% over the first three years. This reduction will include certain savings that will result from partial reductions of the New York State GRT. Industrial customers will see average reductions of 25% relative to 1995 price levels; these decreases will include discounts currently offered to some industrial customers through optional and flexible rate programs. The cumulative rate reductions, net of GRT savings, are estimated to be approximately $112 million, to be experienced on a generally ratable basis over the first three years of the agreement. During the term of the PowerChoice agreement, the Company will be permitted to defer certain costs, associated primarily with environmental remediation, nuclear decommissioning and related costs, and changes in laws, regulations, rules and orders. In years four and five of its rate plan, the Company can request an annual increase in prices subject to a cap of 1% of the all-in price, excluding commodity costs (e.g., transmission, distribution, nuclear, and forecasted CTC). In addition to the price cap, the PowerChoice agreement provides for the recovery of deferrals established in years one through four and cost variations in the MRA financial contracts resulting from indexing provisions of these contracts. The aggregate of the price cap increase and recovery of deferrals is subject to an overall limitation of inflation.

Under the terms of the PowerChoice agreement, all of the Company's customers will be able to choose their electricity supplier in a competitive market by December 1999. The Company will continue to distribute electricity through its distribution and transmission facilities and would be obligated to be the so-called provider of last resort for those customers who do not exercise their right to choose a new electricity supplier.

The PowerChoice agreement provides that the MRA and the contracts executed pursuant thereto shall be found to be prudent. The PowerChoice agreement further provides that the Company shall have a reasonable opportunity to recover its stranded costs, including those associated with the MRA and the contracts executed thereto, through a CTC and, under certain circumstances, through exit fees or in rates for back up service.

Under the PowerChoice agreement, an MRA regulatory asset, aggregating approximately $4,000 million, will be established. In this way, the costs of the MRA would be deferred and amortized over a period not to exceed ten years. The Company's rates under PowerChoice are designed to permit recovery of the MRA regulatory asset and to permit recovery of, and a return on, the remainder of its assets, as appropriate. The PowerChoice agreement, while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.

The PowerChoice agreement calls for the Company to divest all of its fossil and hydro generation assets. Divestiture is intended to be accomplished through an auction. Winning bids would be selected within 11 months of PSC approval of the auction plan, which was filed with the PSC separately from the PowerChoice agreement. The Company will receive a portion of the auction sale proceeds as an incentive to obtain maximum value in the sale. This incentive would be recovered from sale proceeds. The Company agreed that if it does not receive an acceptable bid for an asset, the Company will form a subsidiary to hold any such assets and then legally separate this subsidiary from the Company through a spin-off to shareholders or otherwise. If a bid of zero or below is received for an asset, the Company may keep the asset as part of its regulated business. The auction process will serve to quantify any stranded costs associated with the Company's fossil and hydro generating assets. The Company will have a reasonable opportunity to recover these costs through the CTC and otherwise as described above. After the auction process is complete, the Company has agreed not to own any non-nuclear generating assets in the State of New York, subject to certain exceptions provided in the PowerChoice agreement. Under the terms of the note indenture prepared in connection with the financing of the MRA, the Company will be required to use a majority of the cash portion of net proceeds from the sale of its fossil and hydro generating assets to reduce indebtedness. Such restrictions would not apply in the event that the Company was unable to successfully conclude the consummation of the MRA and therefore of PowerChoice but nonetheless sold such assets.

The PowerChoice agreement contemplates that the Company's nuclear plants will remain part of the Company's regulated business. The Company has been supportive of the creation of a statewide New York Nuclear Operating Company that it expects would improve the efficiency of nuclear units throughout the state. The PowerChoice agreement stipulates that absent such a statewide solution, the Company will file a detailed plan for analyzing other proposals regarding its nuclear assets, including the feasibility of an auction, transfer and/or divestiture of such facilities, within 24 months of PowerChoice approval.

The PowerChoice agreement also allows the Company to form a holding company at its election. The Company plans to seek its shareholders' approval at its 1998 annual meeting to the formation of a holding company, the implementation of which would only occur following various regulatory approvals.

At its public session on February 24, 1998, the PSC voted to approve the PowerChoice agreement, which incorporates the terms of the MRA. Subject to the satisfaction of the conditions to the MRA, the PSC's approval of PowerChoice should allow the Company to consummate the MRA in the first half of 1998. The PowerChoice agreement will only become effective upon the closing of the MRA. In approving PowerChoice, the PSC made the following changes, among others, to the agreement: i) customers who had made a substantial investment in on-site generation as of October 10, 1997 will be grandfathered and not have to pay the CTC; ii) savings from any reduction in the interest rate associated with the debt issued in connection with the MRA financing as compared to assumptions underlying the Company's PowerChoice filing will be deferred for future disposition; and iii) change the generation auction incentive to 15% of proceeds in excess of net book value for non-Oswego assets and 5% of proceeds in excess of $100 million for Oswego assets.

In its written order dated March 20, 1998, the PSC made several other changes to the PowerChoice agreement, in addition to those discussed at the February 24 session. The PSC determined to limit the estimated value of the MRA regulatory asset that can be recovered from customers, to approximately $4,000 million. The estimated value of the MRA regulatory asset includes the issuance of 42.9 million shares of common stock, which the PSC, in determining the recoverable amount of such asset valued at $8 per share. The Company's common stock closed at $12 7/16 per share on March 26, 1998. The accounting implications of the limitation in value are discussed under "Accounting Implications of the PowerChoice Agreement and Master Restructuring Agreement." The PSC also modified the reduction in average residential and commercial rates. The PowerChoice agreement measured the 3.2% reduction against 1995 prices. The PSC determined that the percentage reduction should be applied against the lower of 1995 prices or the most current twelve-month period. To the extent prices for the most current twelve-month period are lower than 1995 prices, the amount of cumulative rate reductions described below will increase. Lastly, the PSC ordered the Company not to proceed to consummate the MRA with respect to one contract held by one developer until a satisfactory resolution of a cogeneration steam host contract is reached.

New York law provides parties the right to appeal the Commission's decision approving the PowerChoice agreement within four months of the date of that decision. In addition, parties have the right to petition the Commission for rehearing of the decision within 30 days of the date of the decision. If a petition for rehearing is filed and the Commission issues a decision on rehearing, parties may appeal the decision on rehearing within four months of the date of the decision on rehearing. Such an appeal or petition for rehearing may be based on the failure of the record to show a reasonable basis for the terms of the PowerChoice agreement and may result in an amendment of the record to correct such failure, in renegotiation of such terms or in renegotiation of the PowerChoice agreement as a whole. There can be no assurance that, on appeal or on rehearing, the approval of the PowerChoice agreement will be upheld or that such appeal or rehearing will not result in terms substantially less favorable to the Company than those described herein.

All of the foregoing discussion of the PowerChoice agreement is qualified in its entirety by the text of the agreement and PSC Order (see Exhibits 10-12 and 10-13).

ACCOUNTING IMPLICATIONS OF THE POWERCHOICE AGREEMENT AND MASTER RESTRUCTURING AGREEMENT

The Company concluded as of December 31, 1996, that the termination, restatement or amendment of IPP contracts and implementation of PowerChoice was the probable outcome of negotiations that had taken place since the PowerChoice announcement. Under PowerChoice, the separated non-nuclear generation business would no longer be rate-regulated on a cost-of-service basis and, accordingly, regulatory assets related to the non-nuclear power generation business, amounting to approximately $103.6 million ($67.4 million after tax or 47 cents per share) were charged against 1996 income as an extraordinary non-cash charge.

As described under "Master Restructuring Agreement and the PowerChoice Agreement," the PSC in its written order issued March 20, 1998 limited the estimated value of the MRA regulatory asset that can be recovered from customers to approximately $4,000 million. The ultimate amount of the regulatory asset to be established may vary based on certain events related to the closing of the MRA. The estimated value of the MRA regulatory asset includes the issuance of 42.9 million shares of common stock, which the PSC, in determining the recoverable amount of such asset valued at $8 per share. Because the value of the consideration to be paid to the IPP Parties can only be determined at the MRA closing, the value of the limitation on the recoverability of the MRA regulatory asset has been estimated at $190 million (85 cents per share) which has been charged to 1997 earnings. The charge to expense was determined as the difference between $8 per share and the Company's closing common stock price on March 26, 1998 of $12 7/16 per share, multiplied by 42.9 million shares. Any variance from the estimate used in determining the charge to expense in 1997, including changes in the common stock price at closing, will be reflected in results of operations in 1998.

Under PowerChoice, the Company's remaining electric business (nuclear generation and electric transmission and distribution business) will continue to be rate-regulated on a cost-of-service basis and, accordingly, the Company continues to apply SFAS No. 71 to these businesses. Also, the Company's IPP contracts, including those restructured under the MRA and those not so restructured will continue to be the obligations of the regulated business. As described under "Master Restructuring Agreement and the PowerChoice Agreement," the consummation of the MRA, as well as implementation of PowerChoice, is subject to a number of contingencies.

In the event the Company is unable to successfully complete the MRA and therefore implement PowerChoice, it would pursue all alternatives including a traditional rate request. However, notwithstanding such a rate request, it is likely that application of SFAS No. 71 would be discontinued for the remaining electric business, since the Company's current rate structure would no longer be sufficient to recover its costs. The resulting non-cash after-tax charges against income, based on regulatory assets and liabilities associated with the nuclear generation and electric transmission and distribution businesses as of December 31, 1997, would be approximately $526.5 million or $3.65 per share. In addition, the Company would be required to reassess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. SFAS No. 121 requires long-lived assets and certain identifiable intangibles held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable or when assets are to be disposed of. In performing the review for recoverability, the Company is required to estimate future undiscounted cash flows expected to result from the use of the asset and/or its disposition. The Company would also be required to determine the extent to which adverse purchase commitments, if any, are required to be recorded as obligations. Various requirements under applicable law and regulations and under corporate instruments, including those with respect to issuance of debt and equity securities, payment of common and preferred dividends, and certain types of transfers of assets could be adversely impacted by any such write-downs.

SFAS No. 71 does not require the Company to earn a return on the regulatory assets in assessing its applicability. In the event the MRA and PowerChoice are implemented, the Company believes that the prices it would charge for electric service over 10 years, including the CTC, assuming no unforeseen reduction in demand or bypass of the CTC or exit fees, will be sufficient to recover the MRA regulatory asset and provide recovery of and a return on the remainder of its assets, as appropriate. In the event the Company could no longer apply SFAS No. 71 in the future, it would be required to record an after-tax non-cash charge against income for any remaining unamortized regulatory assets and liabilities. Depending on when SFAS No. 71 was required to be discontinued, such charge would likely be material to the Company's reported financial condition and results of operations and the Company's ability to pay common and preferred dividends.

The Emerging Issues Task Force ("EITF") of the FASB reached a consensus on Issue No. 97-4 "Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101" in July 1997. The Company discontinued the application of SFAS No. 71 and applied SFAS No. 101 with respect to the fossil and hydro generation business at December 31, 1996, in a manner consistent with the EITF consensus.

With the implementation of PowerChoice, specifically the separation of non-nuclear generation as an entity that would no longer be cost-of-service regulated, the Company is required to assess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. The Company has determined that there is no impairment of its fossil and hydro generating assets. To the extent the proceeds resulting from the sale of the fossil and hydro assets are not sufficient to avoid a loss, the Company would be able to recover such loss through the CTC. The PowerChoice agreement provides for deferral and future recovery of losses, if any, resulting from the sale of the non-nuclear generating assets. The Company's fossil and hydro generation plant assets had a net book value of approximately $1.1 billion at December 31, 1997.

PSC COMPETITIVE OPPORTUNITIES PROCEEDING - ELECTRIC

On May 16, 1996, the PSC issued its Order in the COPS case, which called for a major restructuring of New York State's electric industry. The COPS order called for a competitive wholesale power market and the introduction of retail access for all electric customers. The goals cited in its decision included lowering consumer rates, increasing choice, continuing reliability of service, continuing environmental and public policy programs, mitigating concerns about market power and continuing customer protection and the obligation to serve.

The PSC decision in the COPS proceeding states that recovery of utility stranded costs may be accomplished by a non-bypassable "wires charge" to be imposed by distribution companies.. The PSC decision also states that a careful balancing of customer and utility interests and expectations is necessary, and that the level of stranded cost recovery will ultimately depend upon the particular circumstances of each utility.

On June 10, 1997, the PSC ordered a multi-utility, retail access pilot program that would allow qualified farmers and food processors to shop for electricity and other energy services. The PSC required utilities to adjust the current delivery rates for farmers and food processors, which resulted in rate reductions of about 10 percent for farmers and 3 percent to 6 percent for food processors. Delivery under this program began in late 1997. The Company does not believe that this order will have a material adverse effect on its financial position or results of operations.

On August 27, 1997, the PSC requested comments on its staff's tentative conclusions about how nuclear generation and fossil generation should be treated after decisions are made on the individual electric restructuring agreements currently pending before the PSC. The PSC staff concluded that beyond the transition period (the period covered by the individual restructuring agreements including PowerChoice), nuclear generation should operate on a competitive basis. In addition, the PSC staff concluded that a sale of generation plants to third parties is the preferred means of determining the fair market value of generation plants and offers the greatest potential for the mitigation of stranded costs. The PSC staff also concluded that recovery of sunk costs, including post shutdown costs, would be subject to review by the PSC and this process should take into account mitigation measures taken by the utility, including the steps it has taken to encourage competition in its service area. The Company's nuclear generation assets had a net book value of $1.5 billion (excluding the reserve for decommissioning) at December 31, 1997.

In October 1997, the majority of utilities with interests in nuclear power plants, including the Company, requested that the PSC reconsider its staff's nuclear proposal. In addition, the utilities raised the following issues: impediments to nuclear plants operating in a competitive mode; impediments to the sale of plants; responsibility for decommissioning and disposal of spent fuel; safety and health concerns; and environmental and fuel diversity benefits. In light of all of these issues, the utilities recommended that a more formal process be developed to address those issues.

The three investor-owned utilities, Rochester Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. and the Company, which are currently pursuing formation of a nuclear operating company in New York State, also filed a response with the PSC in October 1997. The response stated that a forced divestiture of the nuclear plants would add uncertainty to developing a statewide approach to operating the plants and requested that such a forced divestiture proposal be rescinded. The response also stated that implementation of a consolidated six-unit operation would contribute to the mitigation of unrecovered nuclear costs. The NYPA, which is also pursuing formation of the nuclear operating company, submitted its own comments which were similar to the comments of the three utilities.

In February 1998, the PSC established a formal proceeding to further examine issues related to nuclear plants and the feasibility of applying market-based pricing to these facilities.

See "Master Restructuring Agreement and PowerChoice Agreement" above for a discussion of the treatment of nuclear operations during the term of PowerChoice.

FERC RULEMAKING ON OPEN ACCESS AND STRANDED COST RECOVERY

In April 1996, the FERC issued FERC Order 888. Order 888 promotes competition by requiring that public utilities owning, operating, or controlling interstate transmission facilities file tariffs which offer others the same transmission services they provide for themselves, under comparable terms and conditions. The Company has complied with this requirement by filing its open access transmission tariff with FERC on July 7, 1996. Based upon settlement discussions with various parties, a proposed settlement was submitted to the FERC in the first quarter of 1997. The settlement has not been approved by the FERC at this time. Hearings were conducted in September 1997 with non-settling parties. A March 1998 Administrative Law Judge's recommended decision in this proceeding recommended lower tariffs than those filed by the Company. The Company is unable to determine the ultimate resolution of this issue or when a decision will be issued by FERC.

Under FERC Order 888, the NYPP was required to file reformed power pooling agreements that establish open, non-discriminatory membership provisions and modify any provisions that are unduly discriminatory or preferential. On January 31, 1997, the NYPP Member Systems (the "Member Systems") submitted a comprehensive proposal to establish an ISO, a New York State Reliability Council ("NYSRC") and a New York Power Exchange ("NYPE") that will foster a fully competitive wholesale electricity market in New York State. The ISO would provide for the reliable operation of the transmission system in New York State and provide nondiscriminatory open access to transmission services under a single ISO tariff. Through the ISO, the transmission owners, including the Company, would be compensated for the use of their transmission systems on a cost-of-service basis. The NYSRC would establish the reliability rules and standards by which the ISO operates the bulk power system. The ISO would also administer the daily electric energy market and the NYPE would facilitate the electric energy market on a day-ahead basis. On May 2, 1997, the Member Systems made a supplemental filing related to the proposed NYSRC and on August 15, 1997, six of the Member Systems filed an application for market-based rate authority in the new wholesale market structure. On December 19, 1997, the Member Systems submitted a revised filing which reflected the fundamental components of the initial January 31, 1997 filing. However, the December 19, 1997 filing provides for additional explanatory materials, incorporates FERC's guidance set forth in FERC orders involving other power pools and ISOs, and sets forth a revised governance structure of the ISO. The Company is unable to predict when FERC will act on these submittals, or whether it will approve the filings with or without modifications. However, the Company's PowerChoice agreement does not condition retail access on the presence of an ISO.

In Order 888, the FERC also stated that it would provide for the recovery of prudent and verifiable wholesale stranded costs where the wholesale customer was able to obtain alternative power supplies as a result of Order 888's open access mandate. Order 888 left to the states the issue of retail stranded cost recovery. Where newly created municipal electric utilities required transmission service from the displaced utility, the FERC stated that it would entertain requests for stranded cost recovery since such municipalization is made possible by open access. The FERC also reserved the right to consider stranded costs on a case-by-case basis if it appeared that open access was being used to circumvent stranded cost review by any regulatory agency.

Numerous parties, including the Company, filed requests for rehearing of Order 888. In March 1997, the FERC issued Order 888-A, which generally affirmed Order 888 and granted rehearing on only a handful of issues. One of those issues was whether the FERC would review stranded costs in annexation cases as it committed to do in municipalization cases. In Order 888-A the FERC stated that it would review stranded costs resulting from territorial annexation by an existing municipal electric system, provided that system relied on transmission from the displaced utility. The FERC denied the Company's request for rehearing on how stranded costs would be calculated and other issues. In November 1997, FERC issued Order 888-B. This Order largely affirmed the positions set forth in Order 888-A while clarifying that the FERC recognizes the existence of concurrent state jurisdiction over stranded costs arising from municipalization. The FERC acknowledged in Order 888-B that the states may be first to address the issue of retail-turned-wholesale stranded costs, and stated that it will give the states substantial deference where they have done so.

In late January 1997, the Company provided 26 communities in St. Lawrence and Franklin counties with estimates they requested of the stranded costs they might be expected to pay if they withdraw from the Company's system to create government-controlled utilities. The preliminary estimate of the combined potential stranded cost liability for the communities ranges from a low of $225 million to a high of $452 million, depending upon the forecast of electricity market prices that is used. These amounts do not include the costs of creating and operating a municipal utility. At this time, 21 of the original 26 communities are still pursuing the matter. If these 21 communities withdrew from the Company's system, the Company would experience a potential revenue loss of approximately $60 million to $65 million per year. In addition, the Company is aware of other communities that are considering municipalization. However, the Company is unable to predict whether those communities would pursue municipalization.

The stranded cost calculations were based on a methodology prescribed by the FERC. Because no municipality has moved forward with condemnation, the value of the Company's facilities has not been deducted from the stranded cost estimates. The stranded costs included in these estimates are the communities' share of obligations that were incurred on behalf of all customers to fulfill the Company's legal obligations to ensure adequate, reliable electricity service. Such legitimate and prudent costs are currently included in electricity rates. Government-mandated payments to IPPs represent the largest single component of these costs. These 21 communities seeking to withdraw from the Company's system also propose to disconnect entirely from the Company's system and to take transmission service from another utility. They believe that, given the provisions of Order 888, FERC would not approve the Company's request for stranded cost recovery under these circumstances. The Company has responded that, regardless of the result at the FERC, opportunities for stranded cost recovery in this matter could also be pursued before the PSC and in a state condemnation proceeding. (See "Master Restructuring Agreement and the PowerChoice Agreement.") The Company is unable to predict the outcome of this matter.

OTHER FEDERAL AND STATE REGULATORY INITIATIVES

PSC Proposal of New IPP Operating and PPA Management Procedures. In August 1996, the PSC proposed to examine the circumstances under which a utility, including the Company, may legally curtail purchases from IPPs; whether utilities should be permitted to collect data that will assist in monitoring IPPs' compliance with federal QF requirements, upon which the mandated purchases are predicated; and if utilities should be allowed to demand security from IPPs to ensure the repayment of amounts accumulated in tracking accounts made under their purchased power contracts.

The PSC noted that some of the current IPP contracts are far above market prices and are causing utilities to seek rate increases. In addition, the PSC stated that its proposal was initiated to protect ratepayers, since it would ensure just and reasonable rates in the event ongoing negotiations between utilities and IPPs fail.

Monitoring. In December 1996, the PSC gave the New York State utilities, including the Company, the authority to collect data to assist them in monitoring IPPs' compliance with both federal QF standards and state requirements. The PSC stated that if QFs are not meeting requirements, the obligation to pay the full contract rate, which is funded by utility ratepayers, is generally excused or mitigated. Furthermore, if the data collected through a QF monitoring program indicates a facility is not meeting federal standards, the utility could petition the FERC to decertify the QF, which could result in penalties that could include cancellation of the contract. A similar penalty could be imposed if it is determined a QF has failed to maintain compliance with state law. Under the monitoring program, QFs are required to submit data as of March 1 each year for the previous calendar year. In accordance with the terms of the MRA, the Company will not implement any QF monitoring program for the IPP Parties. However, the Company continues to monitor those IPPs that are not IPP Parties for continued QF compliance under PSC regulation.

Curtailment. On May 20, 1997, the PSC addressed the procedures under which a utility, including the Company, may legally curtail purchases from IPPs that are QFs, unless curtailment is specifically prohibited by contract. Curtailment is allowed by a FERC rule, under certain operational circumstances when purchases from the QFs will exceed the costs the utility would incur if it generated the power itself. Advance notice must be provided to the QF along with the reasons for such curtailment, which are subject to verification by the PSC either before or after curtailment. The PSC stated that PURPA, which encouraged generation by IPPs, was supposed to be revenue-neutral. However, they noted that this has not been the situation in New York State and ratepayers have been unduly burdened because of their lack of specific curtailment procedures.

The decision to permit curtailment is not likely to affect the PPAs covered by the MRA, which represents approximately 80% of the Company's over-market purchased power obligations, as described previously. However, the decision could affect most of the remaining IPP contracts. The Company is unable to determine the effect of these statements until such a time as there is a final order.

The Company cannot predict whether the PSC will take any action on the firm security issue. However, the firm security issue with respect to the IPP Parties covered under the MRA would be settled upon the closing of the MRA.

Multi-Year Gas Rate Settlement Agreement. The Company, Multiple Intervenors (an unincorporated association of approximately 60 large commercial and industrial energy users with manufacturing and other facilities located throughout New York State) and PSC staff reached a three-year settlement that was conditionally approved by the PSC on December 19, 1996. The PSC ordered conditional approval on the three-year settlement agreement until a final, redrafted agreement, which reflects the Commission's order, is submitted for final approval. The settlement results in a $10 million annual reduction in base rates or a $30 million total reduction over the three-year term of the settlement. This reflects a $19 million reduction in the amount of fixed non-commodity costs to be recoverable in base rates, offset by a $9 million increase in annual base rates. The Company estimates that the combination of in-hand supplier refunds and further reductions in upstream pipeline costs will be sufficient to fund the $19 million annual reduction in non-commodity cost recovery.

If the non-commodity cost reductions exceed $57 million ($19 million annually) during the three-year settlement period, the excess, up to $40 million will be credited to a Contingency Reserve Account ("CRA") to be utilized for ratepayer benefit in the rate year ending October 31, 2000 or beyond. To the extent the actual non-commodity cost reductions exceed $57 million by more than $40 million, the Company may retain any excess subject to a return on equity sharing provision. In the event the non-commodity reductions fall short of the $57 million estimate, the Company will bear the risk of any shortfall. In the event that the termination or restructuring of IPP contracts results in margin (revenues less fuel costs) or peak shaving losses, the margin losses would be collected currently subject to 80%/20% (ratepayer/shareholder) sharing and the peak shaving losses will be deferred to the CRA, subject to limits specified in the settlement.

In return for taking on this risk, the Company has achieved a portion of the revised rate structure that had been proposed to reduce its throughput risk. The Company obtained an ROE cap of 13.5% with 50/50 sharing between ratepayers and shareholders in excess of the cap. The Company also has an opportunity to earn up to $2.25 million annually if its gas commodity costs are lower than a market based target without being subject to the ROE cap. The Company has an equal $2.25 million risk if gas commodity costs exceed the target. An additional major benefit of the revised rate design is that the margin made on each additional new customer will significantly increase to the extent additional throughput does not require additional upstream pipeline capacity for service. This, along with the approval of the Company's Progress Fund, which allows the Company to use utility revenues in an amount not to exceed $11 million in total for the purpose of providing financing for large customers to convert or increase their gas use, will provide new opportunities for growth.

Generic Gas Rate Proceeding. As a result of the generic rate proceeding, in which the PSC ordered all New York utilities to implement a service unbundling beginning in May 1996, nearly 3,000 customers have chosen to buy natural gas from other sources, with the Company continuing to provide transportation service for a separate fee. These changes have not had a material impact on the Company's margins since the margin is traditionally derived from the delivery service and not from the commodity sale. The margin for delivery for residential and commercial aggregation services equals the margin on the traditional sales service classes. To date this migration has not resulted in any stranded costs since the PSC has allowed the utilities to assign the pipeline capacity to the customers converting from sales to transportation. This assignment is allowed during a three-year period ending March 1999, at which time the PSC will decide on methods for dealing with the remaining unassigned or excess capacity. As a part of the generic rate proceeding, all utilities are required to file a report with the PSC in April 1998, describing actions that have been taken to mitigate potential stranded costs as customers migrate to transportation service. In a clarifying order in this proceeding, issued September 4, 1997, the PSC has indicated that it is unlikely that utilities will be allowed to continue to assign pipeline capacity to departing customers after March 1999.

On a separate but parallel path, in September 1997, the PSC issued for comment its staff's position paper on the future of the natural gas industry, including recommendations for increasing competition and expanding customer choice in the natural gas marketplace. The staff proposed, among other things, that all regulated natural gas utilities exit the business of purchasing natural gas for customers over the next five years. This would complete the transition of customers from sales to transportation service only. The regulated utilities would only deliver natural gas purchased by customers from competitive suppliers. If this proposal is adopted by the PSC, then it would eliminate the need to regulate natural gas purchasing practices since market forces would establish natural gas prices.

The position paper identified a number of issues that would need to be resolved in order for this proposal to be successful. The primary issues are the pipeline capacity and gas supply contracts that the local utilities have with interstate pipelines that extend beyond the proposed five-year transition period, the obligation of the utility to serve as supplier of last resort, and the issue of system reliability.

The Company and other parties submitted comments and reply comments to the PSC in late November and December of 1997, respectively. With the exception of the issues to be resolved by the PSC, as mentioned above, the Company does not believe that this proposal will have a material adverse effect on its results of operations or financial condition, since the Company's natural gas margin is derived from the delivery service and not from the commodity sale. The resolution of the issues identified by the PSC could result in unrecovered stranded costs for the Company. The Company is unable to predict how the PSC will resolve those issues. For a discussion of the Company's gas supply, storage and pipeline commitments, see Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Gas Supply, Storage and Pipeline Commitments.")

NRC and Nuclear Operating Matters. In October 1996, the NRC required companies with nuclear plants to provide the NRC with added confidence and assurance that their plants are operated and maintained within the design basis, and any deviations are reconciled in a timely manner. Such information, which was filed within the required 120 days, will be used by the NRC to verify that companies are in compliance with the terms and conditions of their license(s) and NRC regulations. In addition, it will allow the NRC to determine if other inspection activities or enforcement actions should be taken on a particular company.

In the letter transmitting the requested information to the NRC, the Company concluded that it has reasonable assurance that (i) design basis requirements are being translated into operating, maintenance, and testing procedures; and (ii) system, structure and component configuration and performance are consistent with the design basis. Also, the Company has an effective administrative tool for the identification, documentation, notification, evaluation, correction, and reporting of conditions, events, activities, and concerns that have the potential for adversely affecting the safe and reliable operation of Unit 1 and Unit 2.

In April 1997 and December 1997, the Company received notices from the NRC of a $200,000 fine and $50,000 fine, respectively, for violations at Unit 1 and Unit 2. The penalties were for violations related to corrective actions and design control. The Company paid the fines and is implementing corrective action. On January 23, 1998, the Company received notice of a proposed $55,000 fine from the NRC for violations of NRC requirements related to radioactive waste issues. The Company does not plan to contest the proposed NRC fine.

In January 1998, the NRC issued its Systematic Assessment of Licensee Performance (the "SALP") report on Unit 1 and Unit 2, which covers the period June 1996 to November 1997. The SALP report, which is an extensive assessment of the plants' performance in the areas of operations, maintenance, engineering and support, stated that the performance of Unit 1 and Unit 2 was generally good, although ratings were lower than the previous assessment. The Company agrees with the NRC's determination that there are areas of its performance that need improvement and is taking several actions to make those needed improvements.

The Company believes that NRC safety enforcement is becoming more stringent as indicated by the NRC's request for information, fines that the Company has been assessed and lower SALP ratings and that there may be a direct cost impact on companies with nuclear plants as a result. The Company is unable to predict how such a changed operating environment may affect its results of operations or financial condition.

Some owners of older General Electric Company boiling water reactors, including the Company, have experienced cracking in horizontal welds in the plants' core shrouds. In response to industry findings, the Company installed pre-emptive modifications to the Unit 1 core shroud during a 1995 refueling and maintenance outage. The core shroud, a stainless steel cylinder inside the reactor vessel, surrounds the fuel and directs the flow of reactor water through the fuel assemblies.

Inspections conducted as part of the March 1997 refueling and maintenance outage detected cracking in vertical welds not reinforced by the 1995 repairs. On April 8, 1997, the Company filed a comprehensive inspection and analysis report with the NRC that concluded that the condition of the Unit 1 core shroud supports the safe operation of the plant.

On May 8, 1997, the NRC approved the Company's request to operate Unit 1 until the next scheduled mid-cycle outage, late 1998. The Company agreed to propose an inspection plan for the outage and submit the plan to the NRC at least three months before the outage is scheduled to begin. The Company believes it has a strong technical basis to operate Unit 1 without a mid-cycle outage and is seeking the necessary approval from the NRC to postpone the inspections until the unit's refueling and maintenance outage in spring 1999, but there can be no assurance that such approval will be granted.

The Unit 1 refueling and maintenance outage, originally planned to be completed in early April 1997, was completed on May 10, 1997 due to the core shroud issue. On September 15, 1997, Unit 1 was taken out of service due to leaking in one of four back-up condensers. The standby condensers serve as a back-up system for the removal of reactor steam. The condensers are maintained in a ready state during normal plant operations. Tests and inspections were conducted on the remaining condensers and similar conditions were found. On December 10, 1997, Unit 1 was returned to service after the replacement of all four condensers, which cost approximately $6.7 million.

OTHER COMPANY EFFORTS TO ADDRESS COMPETITIVE CHALLENGES

Tax Initiatives. The Company is working with utility, customer and state representatives to explain the negative impact that all utility taxes, including the GRT, are having on rates and the state of the economy. At the same time, the Company is also contesting the high real estate taxes it is assessed by many taxing authorities, particularly those imposed upon generating facilities.

The New York State Legislature passed a state budget in August 1997 which includes a reduction of the GRT over three years. For gas and electric utilities, the tax imposed on gross income will be reduced from 3.5% to 3.25% on October 1, 1998, and from 3.25% to 2.5% on January 1, 2000. The state tax imposed on gross earnings will remain unchanged at .75%, bringing the total GRT to 3.25% -- a full percentage point lower than today's level of 4.25%. The savings from the reduction of the GRT will be passed on to the Company's customers. The Company believes that further tax relief is needed to relieve the Company's customers of high energy costs and to improve New York State's competitive position as the industry moves toward a competitive marketplace.

The following table sets forth a summary of the components of other taxes (exclusive of income taxes) incurred by the Company in the years 1995 through 1997:

	In millions of dollars		
	1997	1996	1995
Property tax expense	$250.7	$249.4	$264.8
Sales tax	13.4	14.1	13.9
Payroll tax	34.1	36.4	37.3
Gross Receipts Tax	184.6	184.1	190.2
Other taxes	0.1	0.5	5.2
Total tax expense	482.9	484.5	511.4
Charged to construction, subsidiaries and regulatory recognition	(11.4)	(8.7)	6.1
Total other taxes	$471.5	$475.8	$517.5

Customer Discounts. In recent years, some industrial customers have found alternative suppliers or are generating their own power. In addition, a weakened economy or attractive energy prices elsewhere have contributed to other industrial customer decisions to relocate or close.

In addressing the threat of further loss of industrial load, the PSC established guidelines to govern flexible electric rates offered by utilities to retain qualified industrial customers. Under these guidelines, the Company filed for a new service tariff in August 1994 (SC-11), under which all new contract rates are administered based on demonstrated industrial and commercial competitive pricing alternatives including, but not limited to, on-site generation, fuel switching, facility relocation and partial plant production shifting. Contracts are for terms not to exceed seven years without PSC approval. In addition, the Company has economic development programs which provide tariff based incentives to retain and grow load.

As of January 1998, the Company has 152 executed contracts under its flexible tariff offerings. These contracts have been signed to mitigate the lost margin impacts associated with customers executing the competitive alternatives mentioned above. In addition, many of these contracts include an increase in production levels and/or attract new customers to the Company's service territory.

In 1997 and 1996, the total amount of customer discounts (economic development programs and flexible pricing) was $90.6 million and $75.5 million, respectively. The Company recovered $46.6 million and $56.7 million in rates, respectively. Pending implementation of **PowerChoice**, the Company budgeted its discounts to increase to approximately $95.4 million in 1998 as some discounts granted in 1997 are in effect for an entire year and further discounts are granted. The Company is aggressively using SC-11 to increase sales to existing customers and to attract new customers to its service territory. With the reduction in industrial prices provided in **PowerChoice**, the level of discounts that have been necessary should decline in the future.

REGULATORY AGREEMENTS/PROPOSALS

(See "Master Restructuring Agreement and the **PowerChoice** Agreement.")

1995 Rate Order. On April 21, 1995, the Company received a rate decision (1995 rate order) from the PSC which approved an approximately $47 million increase in electric revenues and a $4.9 million increase in gas revenues.

YEAR 2000 COMPUTER ISSUE

As the year 2000 approaches, the Company, along with many other companies, could experience potentially serious operational problems, since many computer programs that were developed will not properly recognize calendar dates beginning with the year 2000. Further, there are embedded chips contained within generation, transmission, distribution and gas equipment that may be date-sensitive. In these circumstances where an embedded chip fails to recognize the correct date, electric or gas operations could be adversely affected. The Company is addressing these issues so that its computer systems and, where necessary, its embedded chips will process dates greater than 1999, thereby preventing any adverse operational or financial impacts. The Company has been addressing the year 2000 information technology issue through the remediation and replacement of existing business applications and parts of its technical infrastructure. In late 1997, the services of a leading computer services and consulting firm were retained to conduct an assessment of the Company's entire year 2000 program. As a result of the assessment, a Company-wide year 2000 project management office has been formed and year 2000 project managers have been appointed within each business group and efforts are underway to evaluate the scope of the problem for embedded technologies/process control systems in all business groups within the Company. A Company-wide program director and an executive level steering committee have been put in place to oversee all aspects of the program. The Company is also evaluating the exposure to year 2000 problems of third parties with whom the Company conducts business. The Company expects to complete an inventory of exposures, including an assessment of priorities, costs and resources, by the third quarter of 1998. Failures of the Company and/or third party computer systems and embedded chips could have a material impact on the Company's ability to conduct its business. Until further progress is made on these efforts, management is unable to estimate the total year 2000 compliance expense, but it is in the process of assessing this expense.

RESULTS OF OPERATIONS

Earnings for 1997 were $22.4 million, or 16 cents per share, as compared to $72.1 million, or 50 cents per share, in 1996 and $208.4 million, or $1.44 per share, in 1995. 1997 earnings were negatively impacted by a write-off of $190.0 million or 85 cents per share associated with the portion of the MRA regulatory asset disallowed in rates by the PSC, which was included in other income and deductions in the income statement (see "Master Restructuring Agreement and the PowerChoice Agreement" and "Accounting Implications of the PowerChoice Agreement and Master Restructuring Agreement.") In addition, an increase in industrial customer discounts of $25.2 million not recovered in rates (see Other Company Efforts to Address Competitive Challenges - "Customer Discounts"), and a decline in higher-margin residential sales also adversely impacted 1997 earnings. The lower-margin industrial-special sales (sales by the Company on behalf of NYPA) and industrial sales increased. As a result, total public sales were essentially the same as sales in 1996. This was partially offset by a decline in bad debt expense of $81.1 million in 1997 as compared to 1996 but is $15.3 million over 1995.

Earnings for 1996 include the discontinued application of regulatory accounting principles to the Company's fossil and hydro generation business. The Company reached this conclusion because the March 10, 1997 agreement-in-principle to terminate or restructure power contracts with certain IPPs made probable the implementation of PowerChoice in which the Company proposed to have its non-nuclear generation sell power at competitive prices in the wholesale market. The discontinuance resulted in the write-off of $103.6 million of regulatory assets associated with the fossil and hydro business which was included in the income statement as an extraordinary loss after tax of $67.4 million, or 47 cents per share. Earnings before the extraordinary loss were $139.5 million or 97 cents per share. Excluding the extraordinary loss, earnings for 1996 were lower because of an increase in bad debt expense of $96.4 million or 43 cents per share (see "Financial Position, Liquidity and Capital Resources - Liquidity and Capital Resources"). This was partially offset by a $15.0 million gain on the sale of a 50% interest in CNP that contributed 10 cents per share to 1996 earnings. The Company's request for a temporary rate increase in 1996 was denied by the PSC.

Earnings for 1995 were hurt by lower sales quantities of electricity and natural gas, as compared with amounts used to establish 1995 prices. Sales were primarily affected by the continuing weak economic conditions in upstate New York, loss of industrial customers' load to NYPA and discounts granted. These factors similarly impacted 1996 and 1997 results. In addition, 1995 earnings included the recording of a one-time, non-cash adjustment of prior years' demand-side management ("DSM") incentive revenues, revenues earned under the Unit 1 operating incentive sharing mechanism and a gain on the sale of HYDRA-CO that collectively increased 1995 earnings by 17 cents per share.

The Company's 1997 earned ROE was 0.9% as compared to 2.8% (5.4% before extraordinary loss) in 1996 and 8.4% in 1995. The Company's ROE authorized in the 1995 or last rate setting process is 11.0% for the electric business and 11.4% for the gas business. Factors contributing to earnings below authorized levels in 1997 included, among other things, the PowerChoice charge described above, sales below those forecasted in determining rates, contractual increases in capacity payments to IPPs and increasing discounts to customers. As discussed under "Master Restructuring Agreement and the PowerChoice Agreement" and "Accounting Implications of the PowerChoice Agreement and Master Restructuring

Agreement," the Company forecasts that earnings for the five-year term of the PowerChoice agreement will be substantially depressed. The level of earnings for 1998 will also be impacted, in part, by the date of implementation of PowerChoice and may also be negatively impacted by the financial effects of the January 1998 ice storm (see Item 8. Financial Statements and Supplementary Data - "Note 13. Subsequent Event").

The following discussion and analysis highlights items that significantly affected operations during the three-year period ended December 31, 1997. This discussion and analysis is not likely to be indicative of future operations or earnings, particularly in view of the probable termination, restatement or amendment of IPP contracts and implementation of PowerChoice. It also should be read in conjunction with Item 8. Financial Statements and Supplementary Data and other financial and statistical information appearing elsewhere in this report.

Electric revenues were $3,309 million in both 1997 and 1996, a decrease of $26.1 million, or 0.8% from 1995. As shown in the following table, FAC revenues increased $42.8 million in 1997, primarily as a result of the Company's ability in 1997 to recover increased payments to the IPPs through the FAC. However, this increase was offset by a decrease in revenues from sales to other electric systems and lower electric sales due to warmer weather. Under PowerChoice, revenues may decline as customers choose alternative suppliers. However, the Company will recover stranded costs through the CTC. See "Master Restructuring Agreement and the PowerChoice Agreement."

Electric operating revenues decreased in 1996, primarily due to a decrease in miscellaneous electric revenues. Miscellaneous electric revenues were lower in 1996 primarily because 1995 electric revenues included the recording of $71.5 million of unbilled, non-cash revenues in accordance with the 1995 rate order, $13.0 million of revenues earned under MERIT (an incentive mechanism related to improvement in key performance areas which ended in 1996) and a one-time, non-cash adjustment of prior year's DSM incentive revenues and a reduction in the DSM rebate cost program. However, higher electric sales due to colder weather, an increase in sales to other electric systems, an increase in FAC revenues and higher electric rates (effective April 26, 1995) partly offset those factors that contributed to lower electric revenues. FAC revenues increased $28.3 million in 1996, which primarily reflects the Company's increased payments to the IPPs recovered through the FAC.

	Increase (decrease) from prior year (In millions of dollars)		
Electric revenues	1997	1996	Total
Amortization of unbilled revenues	$ -	$ (77.1)	$(77.1)
Base rates	-	65.3	65.3
Fuel adjustment clause revenues	42.8	28.3	71.1
Changes in volume and mix of sales to ultimate consumers	(12.7)	(28.1)	(40.8)
Sales to other electric systems	(29.6)	24.5	(5.1)
MERIT revenue	-	(13.0)	(13.0)
DSM revenue	-	(26.5)	(26.5)
	$ 0.5	$ (26.6)	$ (26.1)

The FAC is eliminated under the PowerChoice agreement. Changes in FAC revenues are generally margin-neutral (subject to an incentive mechanism discussed in Item 8. Financial Statements and Supplementary Data - "Note 1. Summary of Significant Accounting Policies"), while sales to other utilities, because of regulatory sharing mechanisms and relatively low prices, generally result in low margin contributions to the Company. Thus, fluctuations in these revenue components do not generally have a significant impact on net operating income. Electric revenues reflect the billing of a separate factor for DSM programs, which provided for the recovery of program related rebate costs.

Electric kilowatt-hour sales were 37.1 billion in 1997, 39.1 billion in 1996 and 37.7 billion in 1995. The 1997 decrease of 2.0 billion KWh, or 5.1% as compared to 1996, is related primarily to a 31.0% decrease in sales to other electric systems. (See Item 8. Financial Statements and Supplementary Data - "Electric and Gas Statistics - Electric Statistics"). The 1996 increase of 1.4 billion KWh, or 3.8% as compared to 1995, reflects a 26.2% increase in sales to other electric systems and a 1.2% increase in sales to ultimate customers due to the colder weather. Sales to other electric systems were lower primarily due to a reduction in the availability of nuclear generation as a result of the outages at Unit 1. The Company is anticipating little or no growth in 1998 in sales to ultimate consumers, which will be sensitive to the business climate in its service territory.

Details of the changes in electric revenues and KWh sales by customer group are highlighted in the table below:

	1997 % of Electric	% Increase (decrease) from prior year			
		1997		1996	
Class of service	Revenues	Revenues	Sales	Revenues	Sales
Residential	37.1%	(2.0)%	(2.0)%	3.1%	0.5%
Commercial	37.3	(0.3)	(0.1)	-	(0.4)
Industrial	16.1	1.2	0.6	0.2	1.2
Industrial-Special	1.9	5.8	4.2	3.9	6.7
Municipal service	1.6	1.4	(4.5)	5.8	7.4
Total to ultimate consumers	94.0	(0.6)	-	1.4	1.2
Other electric systems	2.5	(26.1)	(31.0)	27.5	26.2
Miscellaneous	3.5	70.4	(100.0)	(57.8)	(17.7)
Total	100.0%	- %	(5.1)%	(0.8)%	3.8%

As indicated in the table below, internal generation decreased 10.1% in 1997, principally due to the outage at Unit 1 and a reduction in hydroelectric power as a result of lower than normal precipitation in the summer months. In 1997, Unit 1 was out of service for 153 days, due to a planned refueling and maintenance outage (which took 68 days) and for the emergency condenser replacement (which took approximately 85 days) while in 1996, Unit 2 was out of service for a 36 day planned refueling and maintenance outage. (See "Other Federal and State Regulatory Initiatives - NRC and Nuclear Operating Matters.") The amount of electricity delivered to the Company by the IPPs decreased by approximately 277 GWh or 2.0%. However, total IPP costs increased by approximately $18.0 million or 1.7%, as discussed below. (See "Master Restructuring Agreement and the PowerChoice Agreement").

millions of dollars)	1997		1996		1995		% Change from prior year 1997 to 1996		1996 to 1995	
	GWh	Cost	GWh	Cost	GWh	Cost	GWh	Cost	GWh	Cost
Fuel for electric generation:										
Coal	7,459	$ 106.4	7,095	$ 100.6	6,841	$ 97.9	5.1%	5.8%	3.7%	2.8%
Oil	701	32.2	462	21.1	537	21.3	51.7	52.6	(14.0)	(0.9)
Natural gas	394	8.6	319	9.2	996	20.2	23.5	(6.5)	(68.0)	(54.5)
Nuclear	6,339	33.0	8,243	47.7	7,272	43.3	(23.1)	(30.8)	13.4	10.2
Hydro	2,905	-	3,679	-	2,971	-	(21.0)	-	23.8	-
	17,798	180.2	19,798	178.6	18,617	182.7	(10.1)	0.9	6.3	(2.2)
Electricity purchased:										
IPPs:										
Capacity	-	220.8	-	212.8	-	181.2	-	3.8	-	17.4
Energy and taxes	13,520	885.7	13,797	875.7	14,023	798.7	(2.0)	1.1	(1.6)	9.6
Total IPP purchases	13,520	1,106.5	13,797	1,088.5	14,023	979.9	(2.0)	1.7	(1.6)	11.1
Other	9,421	130.2	9,569	130.6	9,463	126.5	(1.5)	(0.3)	1.1	3.2
	22,941	1,236.7	23,366	1,219.1	23,486	1,106.4	(1.8)	1.4	(0.5)	10.2
Total generated and purchased	40,739	1,416.9	43,164	1,397.7	42,103	1,289.1	(5.6)	1.4	2.5	8.4
Fuel adjustment clause	-	(1.3)	-	(33.3)	-	14.8	-	(96.1)	-	(325.0)
Losses/Company use	3,603	-	4,037	-	4,419	-	(10.8)	-	(8.6)	-
	37,136	$1,415.6	39,127	$1,364.4	37,684	$1,303.9	(5.1)%	3.8%	3.8%	4.6%

The above table presents the total costs for purchased electricity, while reflecting only fuel costs for Company generation. Other costs of generation, such as taxes, other operating expenses and depreciation are included within other income statement line items.

The Company's management of its IPP power supply generally divides the projects into three categories: hydroelectric, "must run" cogeneration and schedulable cogeneration projects.

Following a higher than normal spring run off, the precipitation in the summer months was lower than usual. As a result, hydroelectric IPP projects delivered 242 GWh or 13.7% less under PPAs than they did for the same period last year, representing decreased payments to those IPPs of $15.7 million.

A substantial portion of the Company's portfolio of IPP projects operate on a "must run" basis. This means that they tend to run at maximum production levels regardless of the need for or economic value of the electricity produced. Output from "must run" cogeneration IPPs was 230 GWh or 2.6% lower than produced last year, in part due to lower energy purchases from the Sithe Independence plant. However, payments to those IPPs were $12.8 million higher. This was due to a combination of output turndown arrangements with individual projects and escalating contract rates. A turndown arrangement is an agreement where the Company compensates an IPP to reduce the output from their facility. Although output is reduced, the net economic impact is favorable to the Company and its customers since the electricity is replaced from the market or other lower cost sources.

Quantities purchased from schedulable cogeneration IPPs increased 195 GWh or 6.3% and payments increased $20.9 million. The increased payments are largely due to escalating contract rates for capacity (fixed) and increased volumes of energy. The terms of these PPAs allow the Company to schedule (with certain constraints) energy deliveries and pay for the energy supplied. In addition, the Company is required to make fixed payments if the IPP plants remain available for service. (See Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Long-term Contracts for the Purchase of Electric Power").

Gas revenues decreased by $24.7 million, or 3.6% in 1997, and increased by $99.9 million, or 17.2%, in 1996. As shown in the table below, gas revenues decreased in 1997 primarily due to decreased sales to ultimate customers as a result of the migration of commercial sales customers to the transportation class, decreased spot market sales and a decrease in base rates of $5.9 million in accordance with the 1996 rate order. This was partially offset by higher gas adjustment clause recoveries and an increase in revenues from the transportation of customer-owned gas (see "Other Federal and State Regulatory Initiatives - Generic Gas Rate Proceeding").

Gas revenues increased in 1996 primarily due to increased sales to ultimate customers due to colder weather, increased spot market sales, higher gas adjustment clause recoveries, an increase in revenues from the transportation of customer-owned gas and an increase in base rates of $3.1 million in accordance with the 1995 rate order.

Rates for transported gas (excluding aggregation services) yield lower margins than gas sold directly by the Company. Therefore, increases in the volume of gas transportation services have not had a proportionate impact on earnings, particularly in instances where customers that took direct service from the Company move to a transportation-only class. In addition, changes in purchased gas adjustment clause revenues are generally margin-neutral.

	Increase (decrease) from prior year (In millions of dollars)		
Gas revenues	1997	1996	Total
Base rates.	$(5.9)	$ 3.1	$ (2.8)
Transportation of customer-owned gas.	5.3	2.1	7.4
Purchased gas adjustment clause revenues. . .	45.3	30.8	76.1
Spot market sales	(30.8)	34.0	3.3
Changes in volume and mix of sales to ultimate consumers	(38.6)	29.9	(8.8)
	$(24.7)	$ 99.9	$75.2

Gas sales, excluding transportation of customer-owned gas and spot market sales, were 78.7 million Dth in 1997, a 7.3% decrease from 1996, and a 0.3% increase from 1995. (See Item 8. Financial Statements and Supplementary Data - "Electric and Gas Statistics - Gas Statistics"). The decrease in 1997 was in all ultimate consumer classes, in part due to the warmer weather. In addition, spot market sales (sales for resale), which are generally from the higher priced gas available to the Company and therefore yield margins that are substantially lower than traditional sales to ultimate customers, decreased 8.0 million Dth. This was partially offset by an increase in transportation volumes of 18.1 million Dth or 13.5% to customers purchasing gas directly from producers. The Company has experienced an increase in customers of approximately 17,800 since 1995, primarily in the residential class, an increase of 3.5%.

Changes in gas revenues and Dth sales by customer group are detailed in the table below:

Class of service	1997 % of Gas Revenues	% Increase (decrease) from prior year: 1997 Revenues	1997 Sales	1996 Revenues	1996 Sales
Residential	66.4%	4.5%	(2.7)%	13.3%	9.4%
Commercial	22.6	(8.7)	(13.0)	13.0	6.4
Industrial	1.0	(50.9)	(50.1)	15.6	4.1
Total to ultimate consumers	90.0	(0.3)	(7.3)	13.3	8.3
Other gas systems	-	(5.8)	(6.7)	(81.9)	(81.4)
Transportation of customer-owned gas	8.5	10.5	13.5	4.3	(6.9)
Spot market sales	1.0	(82.9)	(76.6)	1,099.1	507.0
Miscellaneous	0.5	263.1	-	(82.2)	-
Total	100.0%	(3.6)%	1.7%	17.2%	2.3%

The total cost of gas purchased decreased 6.6% in 1997 and increased 34.0% in 1996. The cost fluctuations generally correspond to sales volume changes, as spot market sales activity decreased, as well as changes in gas prices. The Company sold 2.5, 10.5 and 1.7 million Dth on the spot market in 1997, 1996 and 1995, respectively. The total cost of gas decreased $24.4 million in 1997. This was the result of a 5.3 million decrease in Dth purchased and withdrawn from storage for ultimate consumer sales ($18.8 million) and a $22.5 million decrease in Dth purchased for spot market sales, partially offset by a 3.3% increase in the average cost per Dth purchased ($10.7 million) and a $6.3 million increase in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause.

The total cost of gas purchased increased $93.8 million in 1996. This was the result of a 9.3 million increase in Dth purchased and withdrawn from storage for ultimate consumer sales ($29.6 million), a $25.6 million increase in Dth purchased for spot market sales and a 12.9% increase in the average cost per Dth purchased ($38.7 million). Gas purchased for spot market sales decreased $22.5 million in 1997 and increased $25.6 million in 1996. The Company's net cost per Dth sold, as charged to expense and excluding spot market purchases, increased to $3.82 in 1997 from $3.62 in 1996 and was $3.17 in 1995.

Through the electric and purchased gas adjustment clauses, costs of fuel, purchased power and gas purchased, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company's electric FAC provides for a partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. The Company absorbed losses of approximately $11.8 million, $1.4 million and $13.1 million in 1995, 1996 and 1997, respectively. Under PowerChoice, the FAC will be terminated. The Company does not believe that the elimination of the FAC will have a material adverse effect on its financial condition, as a result of its management of (1) power supplies provided through: (i) the operation of its own power plants, and future power purchase arrangements as part of the planned auction of its fossil and hydro assets, (ii) fixed power purchases from NYPA and remaining IPPs and (iii) fixed and indexed swap arrangements with IPP Parties and (2) the transfer of the risk associated with electricity commodity prices to the customer through implementation of retail access included in the PowerChoice agreement.

Other operation and maintenance expense decreased in 1997 by $92.9 million, or 10.0%, as compared to an increase of $110.3 million or 13.5% in 1996. These changes in 1996 and 1997 each result primarily from a change in 1996 in the

Company's assessment of uncollectible customer accounts, which gives greater recognition to the increased risk of collecting past due customer bills, resulting in increases in the Company's allowance for doubtful accounts and a significantly higher expense recognition in 1996. Bad debt expense was $31.2 million, $127.6 million and $46.5 million in 1995, 1996 and 1997, respectively. In 1997, write-offs were $39.0 million and the Company incurred a $10.5 million increase in allowance for doubtful accounts. The increase in the allowance for doubtful accounts was attributable to increases in the collection risk associated with residential accounts receivable and arrears. The Company has implemented a number of collection initiatives that are expected to result in lower arrears levels and potentially lower the allowance for doubtful accounts. Other operation and maintenance expense also decreased in 1997 as a result of a reduction in administrative and general expenses of $15.8 million, primarily due to a reduction in legal costs.

Other income and deductions decreased by $200.9 million in 1997 and increased by $32.9 million in 1996. Despite higher interest income ($12.0 million) related to increasing cash balances, "other income and deductions" decreased in 1997 due to the write-off of $190.0 million associated with the estimated portion of the MRA regulatory asset disallowed in rates and lower subsidiary earnings. In addition, "other income and deductions" was lower in 1997, since 1996 reflected a gain on the sale of a 50% interest in CNP ($15.0 million). The 1996 increase also reflected higher interest income ($10.9 million) as a result of an increase in temporary cash investments. In addition, "other income and deductions" was higher in 1996 since there were customer service penalties and certain other items written off because they were disallowed in rates in 1995.

Federal and foreign income taxes decreased by $42.4 million in 1997 and $56.9 million in 1996 primarily due to a decrease in pre-tax income. **Other taxes** decreased by $4.4 million in 1997 and decreased by $41.6 million in 1996. The 1997 decrease was primarily due to lower payroll taxes ($2.3 million) and lower sales taxes ($0.7 million). The 1996 decrease was primarily as a result of lower real estate taxes ($15.4 million), lower GRTs ($6.1 million) primarily due to a reduction in the GRT surcharge during 1996, lower New York State excess dividend tax accrual due to a suspension of the common stock dividend ($4.6 million) and year-to-year differences in the accounting for regulatory deferrals ($15.2 million) associated primarily with a settlement of tax issues with respect to the Company's Dunkirk facility.

Interest charges remained fairly constant for the years 1995 through 1997. However, dividends on preferred stock decreased by $0.9 million and $1.3 million in 1997 and 1996, respectively. Dividends on preferred stock decreased in 1997 primarily due to a reduction in preferred stock outstanding through sinking fund redemptions and decreased in 1996 primarily due to a decrease in the cost of variable rate issues. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 7.81% and 7.04%, respectively, in 1997 from 7.71% and 7.09%, respectively, in 1996 and from 7.77% and 7.19%, respectively, in 1995.

EFFECTS OF CHANGING PRICES

The Company is especially sensitive to inflation because of the amount of capital it typically needs and because its prices are regulated using a rate base methodology that reflects the historical cost of utility plant.

The Company's consolidated financial statements are based on historical events and transactions when the purchasing power of the dollar was substantially different than now. The effects of inflation on most utilities, including the Company, are most significant in the areas of depreciation and utility plant. The Company could not replace its non-nuclear utility plant and equipment for the historical cost value at which they are recorded on the Company's books. In addition, the Company would not replace these with identical assets due to technological advances and competitive and regulatory changes that have occurred. In light of these considerations, the depreciation charges in operating expense do not reflect the cost of providing service if new generating facilities were installed. The Company will seek additional revenue or reallocate resources, if possible, to cover the costs of maintaining service as assets are replaced or retired.

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

Financial Position. The Company's capital structure at December 31, 1997 was 52.8% long-term debt, 7.8% preferred stock and 39.4% common equity, as compared to 53.1%, 7.9% and 39.0% respectively, at December 31, 1996. The culmination of the termination, restatement or amendment of IPP contracts will significantly increase the leverage of the Company to nearly 65% at the time of closing. Through the anticipated increased operating cash flow resulting from the MRA and PowerChoice agreement, the planned rapid repayment of debt should deleverage the Company over time. Book value of the common stock was $18.03 per share at December 31, 1997, as compared to $17.91 per share at December 31, 1996. With the issuance of equity at below book value to the IPP Parties as part of the MRA, book value per share will be diluted. In addition, earnings per share will be diluted by the effect of the issuance to the IPP Parties of approximately 42.9 million shares of the Company's common stock.

The Company's EBITDA for 1997 was approximately $897 million, and upon implementation of the MRA and PowerChoice is expected to increase to approximately $1,300 million to $1,500 million per year. EBITDA represents earnings before interest charges, interest income, income taxes, depreciation and amortization, and extraordinary items. EBITDA is a non-GAAP measure of cash flows and is presented to provide additional information about the Company's ability to meet its future requirements for debt service which would increase significantly upon consummation of the MRA. EBITDA should not be considered an alternative to net income as an indicator of operating performance or as an alternative to cash flows, as presented on the Consolidated Statement of Cash Flows, as a measure of liquidity.

The 1997 ratio of earnings to fixed charges was 1.39 times. The ratios of earnings to fixed charges for 1996 and 1995 were 1.57 times and 2.29 times, respectively. The change in the ratio was primarily due to changes in earnings during the period. Assuming the MRA is implemented, the ratio of earnings to fixed charges will substantially decrease in the future, since the MRA and PowerChoice agreement will have the effect of substantially depressing earnings during its five-year term, while at the same time substantially improving operating cash flows. The primary objective of the MRA is to convert a large and growing off-balance sheet payment obligation that threatens the financial viability of the Company into a fixed and manageable capital obligation.

Common Stock Dividend. The Board of Directors omitted the common stock dividend beginning the first quarter of 1996. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addresses growing pressure from mandated power purchases and weaker sales and is the primary reason for the increase in the cash balance. In making future dividend decisions, the Board of Directors will evaluate, along with standard business considerations, the financial condition of the Company, the closing of the MRA and implementation of PowerChoice, or the failure to implement such actions, contractual restrictions that might be entered into in conjunction with financing the MRA, the degree of competitive pressure on its prices, the level of available cash flow and retained earnings and other strategic considerations. The Company expects to dedicate a substantial portion of its future expected positive cash flow to reduce the leverage created in connection with the implementation of the MRA. The PowerChoice agreement establishes limits to the annual amount of common and preferred stock dividends that can be paid by the regulated business. The limit is based upon the amount of net income each year, plus a specified amount ranging from $50 million in 1998 to $100 million in 2000. The dividend limitation is subject to review after the term of the PowerChoice agreement. Furthermore, the Company forecasts that earnings for the five-year term of the PowerChoice agreement will be substantially depressed, as non-cash amortization of the MRA regulatory asset is occurring and the interest costs on the IPP debt is the greatest. See "Accounting Implications of the PowerChoice Agreement and Master Restructuring Agreement."

Construction and Other Capital Requirements. The Company's total capital requirements consist of amounts for the Company's construction program (see Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Construction Program,"). The January 1998 ice storm damage restoration costs may further add to these requirements (see Item 8. Financial Statements and Supplementary Data - "Note 13. Subsequent Event"), nuclear decommissioning funding requirements (See Item 8. Financial Statements and Supplementary Data - "Note 3. Nuclear Operations - Nuclear Plant Decommissioning" and - "NRC Policy Statement and Proposal"), working capital needs, maturing debt issues and sinking fund provisions on preferred stock, as well as requirements to complete the MRA and accomplish the restructuring contemplated by the PowerChoice agreement. Annual expenditures for the years 1995 to 1997 for construction and nuclear fuel, including related AFC and overheads capitalized, were $345.8 million, $352.1 million and $290.8 million, respectively, and are budgeted to be approximately $358 million for 1998 and to range from $279 - $352 million for each of the subsequent four years. These estimates include construction expenditures for non-nuclear generation of $20 million to $38 million per year.

In addition to the assumed cost of the MRA requirements, as described below, mandatory debt and preferred stock retirements are expected to add approximately another $77 million to the 1998 estimate of capital requirements. The estimate of construction additions included in capital requirements for the period 1998 to 2002 will be reviewed by management to give effect to the storm restoration costs and the overall objective of further reducing construction spending where possible. See discussion in "Liquidity and Capital Resources" section below, which describes how management intends to meet its financing needs for this five-year period.

Under the MRA, the Company will pay an aggregate of $3,616 million in cash. The Company expects to issue senior unsecured debt to fund this requirement, which is expected to consist of both debt issued through a public market offering and debt issues to banks which would serve to replace its existing $804 million senior debt facility, discussed below. The Company's preferred shareholders gave the Company approval to increase the amount of unsecured debt the Company may issue by $5 billion. Previously, the Company was able to issue $700 million under the restrictions of its amended Certificate of Incorporation. This authorization will enable the issuance of unsecured debt to consummate the MRA. In addition, the Company believes that the ability to use unsecured indebtedness will increase its flexibility in planning and financing its business activities.

Liquidity and Capital Resources. External financing plans are subject to periodic revision as underlying assumptions are changed to reflect developments, market conditions and, most importantly, conclusion of the MRA and implementation of PowerChoice. The ultimate level of financing during the period 1998 through 2002 will be affected by, among other things: the timing and outcome of the MRA and the cash tax benefits anticipated because the MRA is expected to result in a net operating loss for 1998 income tax purposes; the implementation of the PowerChoice agreement, levels of common dividend payments, if any, and preferred dividend payments; the results of the auction of the Company's fossil and hydro assets; the Company's competitive position and the extent to which competition penetrates the Company's markets; uncertain energy demand due to the weather and economic conditions; and the effects of the ice storm that struck a portion of the Company's service territory in early 1998. The proceeds of the sale of the fossil and hydro assets will be subject to the terms of the Company's mortgage indenture and the note indenture that will be entered into in connection with the MRA debt financing. The Company could also be affected by the outcome of the NRC's consideration of new rules for adequate financial assurance of nuclear decommissioning obligations. (See Item 8. Notes to Consolidated Financial Statements - "Note 3. Nuclear Operations - NRC Policy Statement and Proposal" and "Note 13. Subsequent Event").

The Company has an $804 million senior debt facility with a bank group, consisting of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA. The interest rate applicable to the senior debt facility is variable based on certain rate options available under the agreement and currently approximates 7.7% (but is capped at 15%). As of December 31, 1997, the amount outstanding under the senior debt facility was $529 million, consisting of $105 million under the term loan facility and a $424 million letter of credit, leaving the Company with $275 million of borrowing capability under the facility. The facility expires on June 30, 1999 (subject to earlier termination if the Company separates its fossil/hydro generation business from its transmission and distribution business, or any other significant restructuring plan). The Company is currently negotiating with the lenders to replace the senior debt facility with a larger facility to finance a portion of the MRA.

This facility is collateralized by first mortgage bonds which were issued on the basis of additional property under the earnings test required under the mortgage trust indenture ("First Mortgage Bonds"). As of December 31, 1997, the Company could issue an additional $1,396 million aggregate principal amount of First Mortgage Bonds under the Company's mortgage trust indenture. This amount is based upon retired bonds without regard to an interest coverage test. The Company is presently precluded from issuing First Mortgage Bonds based on additional property.

Although no assurance can be provided, the Company believes that the closing of the MRA and implementation of PowerChoice will result in substantially depressed earnings during its five-year term, but will substantially improve operating cash flows. There is risk throughout the electric industry that credit ratings could decline if the issue of stranded cost recovery is not satisfactorily resolved. In the event the MRA is not closed, and comparable solutions are not available, the Company will undertake other actions necessary to act in the best interests of stockholders and other constituencies.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a periodic basis. This approach generally results in the Company showing a working capital deficit. This has not been the case in the last two years as the Company's cash balance has increased, reflecting suspension of the common stock dividend in 1996. Working capital deficits may also be a result of the seasonal nature of the Company's operations as well as timing differences between the collection of customer receivables and the payment of fuel and purchased power costs. The Company believes it has sufficient borrowing capacity to fund deficits as necessary in the near term. However, the Company's borrowing capacity to fund such deficits may be affected by the factors discussed above relating to the Company's external financial plans.

Since 1995, past-due accounts receivable have increased significantly. A number of factors have contributed to the increase, including rising prices (particularly to residential customers). Rising prices have been driven by increased payments to IPPs and high taxes and have been passed on in customers' bills. The stagnant economy in the Company's service territory since the early 1990's has adversely affected collection of past-due accounts. Also, laws, regulations and regulatory policies impose more stringent collection limitations on the Company than those imposed on business in general; for example, the Company faces more stringent requirements to terminate service during the winter heating season. The increase in the allowance for doubtful accounts was attributable to the reassessment of the collection risk associated with residential accounts receivable and arrears. The Company has implemented a number of collection initiatives that are expected to result in lower arrears levels and potentially lower the allowance for doubtful accounts. The Company has and will continue to implement a variety of strategies to improve its collection of past due accounts and reduce its bad debt expense.

The information gathered in developing these strategies enabled management to update its risk assessment of the accounts receivable portfolio. Based on this assessment, management determined that the level of risk associated primarily with the older accounts had increased and the historical loss experience no longer applied. Accordingly, the Company determined that a significant portion of the past-due accounts receivable (principally of residential customers) might be uncollectible, and had written-off a substantial number of these accounts as well as increased its allowance for doubtful accounts in 1996. In 1997 and 1996, the Company charged $46.5 million and $127.6 million, respectively to bad debt expense. The allowance for doubtful accounts is based on assumptions and judgments as to the effectiveness of collection efforts. Future results with respect to collecting the past-due receivables may prove to be different from those anticipated. Although the Company has experienced a level of improvement in collection efforts, future results are necessarily dependent upon the following factors, including, among other things, the effectiveness of the strategies discussed above, the support of regulators and legislators to allow utilities to move towards commercial collection practices and improvement in the condition of the economy in the Company's service territory. The Company has been pursuing PowerChoice to address high prices that are the result of traditional price regulation, but the introduction of competition requires that policies and practices that were central to traditional regulation, including those involving collections, be changed so as not to jeopardize the benefits of competition.

Net cash provided by operating activities decreased $162.8 million in 1997 primarily due to a decrease of $105.9 million in the amount of accounts receivable sold under the accounts receivable sales program (which the Company has budgeted to restore in 1998) partially offset by an increase in deferred taxes of $53.9 million.

Net cash used in investing activities increased $62.4 million in 1997 primarily as a result of an increase in other cash investments of $116.1 million offset by a decrease in the acquisition of utility plant of $62.9 million.

Net cash used in financing activities decreased $106.1 million, primarily due to a net reduction of $94.7 million in the payments on long-term debt.

Item 8. Financial Statements and Supplementary Data

A. Financial Statements

Report of Management
Report of Independent Accountants
Consolidated Statements of Income and Retained Earnings for each of the three years in the period ended December 31, 1997.
Consolidated Balance Sheets at December 31, 1997 and 1996.
Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 1997.
Notes to Consolidated Financial Statements.

REPORT OF MANAGEMENT

The consolidated financial statements of the Company and its subsidiaries were prepared by and are the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records and protection of assets. This system includes communication through written policies and procedures, an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program. In addition, the Company has a Corporate Policy Register and a Code of Business Conduct (the "Code") that supply employees with a framework describing and defining the Company's overall approach to business and require all employees to maintain the highest level of ethical standards as well as requiring all management employees to formally affirm their compliance with the Code.

The financial statements have been audited by Price Waterhouse LLP, the Company's independent accountants, in accordance with GAAP. In planning and performing its audit, Price Waterhouse LLP considered the Company's internal control structure in order to determine auditing procedures for the purpose of expressing an opinion on the financial statements, and not to provide assurance on the internal control structure. The independent accountants' audit does not limit in any way management's responsibility for the fair presentation of the financial statements and all other information, whether audited or unaudited, in this Annual Report. The Audit Committee of the Board of Directors, consisting of five outside directors who are not employees, meets regularly with management, internal auditors and Price Waterhouse LLP to review and discuss internal accounting controls, audit examinations and financial reporting matters. Price Waterhouse LLP and the Company's internal auditors have free access to meet individually with the Audit Committee at any time, without management being present.

William E. Davis

William E. Davis
Chairman of the Board and
Chief Executive Officer
Niagara Mohawk Power Corporation

REPORT OF INDEPENDENT ACCOUNTANTS

To the Stockholders and
Board of Directors of
Niagara Mohawk Power Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and retained earnings and of cash flows present fairly, in all material respects, the financial position of Niagara Mohawk Power Corporation and its subsidiaries at December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in Note 2, the Company believes that it continues to meet the requirements for application of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71) for its nuclear generation, electric transmission and distribution and gas businesses. In the event that the Company is unable to complete the termination, restatement or amendment of the independent power producer contracts, this conclusion could change in 1998 and beyond, resulting in material adverse effects on the Company's financial condition and results of operations.

As discussed in Note 2, the Company discontinued application of SFAS No. 71 for its non-nuclear generation business in 1996.

Price Waterhouse LLP
Syracuse, New York
March 26, 1998

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

Consolidated Statements of Income and Retained Earnings

In thousands of dollars For the year ended December 31,	1997	1996	1995
Operating revenues:			
Electric	$3,309,441	$3,308,979	$3,335,548
Gas	656,963	681,674	581,790
	3,966,404	3,990,653	3,917,338
Operating expenses:			
Fuel for electric generation	179,455	181,486	165,929
Electricity purchased	1,236,108	1,182,892	1,137,937
Gas purchased	345,610	370,040	276,232
Other operation and maintenance expenses	835,282	928,224	817,897
Depreciation and amortization (Note 1)	339,641	329,827	317,831
Other taxes	471,469	475,846	517,478
	3,407,565	3,468,315	3,233,304
Operating income	558,839	522,338	684,034
Other Income and (Deductions):			
PowerChoice charge (Note 2)	(190,000)	-	-
Other income (Note 1)	24,997	35,943	3,069
	(165,003)	35,943	3,069
Income before interest charges	393,836	558,281	687,103
Interest charges (Note 1)	273,906	278,033	279,674
Income before federal and foreign income taxes	119,930	280,248	407,429
Federal and foreign income taxes (Note 7)	60,095	102,494	159,393
Income before extraordinary item	59,835	177,754	248,036
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes of $36,273 in 1996 (Note 2)	-	(67,364)	-
Net Income	59,835	110,390	248,036
Dividends on preferred stock	37,397	38,281	39,596
Balance available for common stock	22,438	72,109	208,440
Dividends on common stock	-	-	161,650
	22,438	72,109	46,790
Retained earnings at beginning of year	657,482	585,373	538,583
Retained earnings at end of year	$ 679,920	$ 657,482	$ 585,373
Average number of shares of common stock outstanding (in thousands)	144,404	144,350	144,329
Basic and diluted earnings per average share of common stock before extraordinary item	$ 0.16	$ 0.97	$ 1.44
Extraordinary item	$ -	$ (0.47)	$ -
Basic and diluted earnings per average share of common stock	$ 0.16	$ 0.50	$ 1.44
Dividends on common stock paid per share	$ -	$ -	$ 1.12

() Denotes deduction

The accompanying notes are an integral part of these financial statements

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

Consolidated Balance Sheets

At December 31,	In thousands of dollars 1997	1996
ASSETS		
Utility plant (Note 1):		
Electric plant	$ 8,752,865	$ 8,611,419
Nuclear fuel	577,409	573,041
Gas plant	1,131,541	1,082,298
Common plant	319,409	292,591
Construction work in progress	294,650	279,992
Total utility plant	11,075,874	10,839,341
Less: Accumulated depreciation and amortization	4,207,830	3,881,726
Net utility plant	6,868,044	6,957,615
Other property and investments	371,709	257,145
Current assets:		
Cash, including temporary cash investments of $315,708 and $223,829, respectively	378,232	325,398
Accounts receivable (less allowance for doubtful accounts of $62,500 and $52,100, respectively) (Notes 1 and 9)	492,244	373,305
Materials and supplies, at average cost:		
Coal and oil for production of electricity	27,642	20,788
Gas storage	39,447	43,431
Other	118,308	120,914
Prepaid taxes	15,518	11,976
Other	20,309	25,329
	1,091,700	921,141
Regulatory assets (Note 2):		
Regulatory tax asset	399,119	416,599
Deferred finance charges	239,880	239,880
Deferred environmental restoration costs (Note 9)	220,000	225,000
Unamortized debt expense	57,312	65,993
Postretirement benefits other than pensions	56,464	60,482
Other	204,049	206,352
	1,176,824	1,214,306
Other assets	75,864	77,428
	$ 9,584,141	$ 9,427,635

The accompanying notes are an integral part of these financial statements

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

Consolidated Balance Sheets

At December 31,	1997 (In thousands of dollars)	1996 (In thousands of dollars)
CAPITALIZATION AND LIABILITIES		
Capitalization (Note 5):		
Common stockholders' equity:		
Common stock, issued 144,419,351 and 144,365,214 shares, respectively.	$ 144,419	$ 144,365
Capital stock premium and expense	1,779,688	1,783,725
Retained earnings	679,920	657,482
	2,604,027	2,585,572
Non-redeemable preferred stock	440,000	440,000
Mandatorily redeemable preferred stock	76,610	86,730
Long-term debt	3,417,381	3,477,879
Total capitalization	6,538,018	6,590,181
Current liabilities:		
Long-term debt due within one year (Note 5).	67,095	48,084
Sinking fund requirements on redeemable preferred stock (Note 5)	10,120	8,870
Accounts payable	263,095	271,830
Payable on outstanding bank checks	23,720	32,008
Customers' deposits	18,372	15,505
Accrued taxes	9,005	4,216
Accrued interest	62,643	63,252
Accrued vacation pay	36,532	36,436
Other	64,756	52,455
	555,338	532,656
Regulatory liabilities (Note 2):		
Deferred finance charges	239,880	239,880
Other liabilities:		
Accumulated deferred income taxes (Notes 1 and 7). . . .	1,320,532	1,357,518
Employee pension and other benefits (Note 8)	240,211	238,688
Deferred pension settlement gain	12,438	19,269
Unbilled revenues (Note 1)	43,281	49,881
Other	414,443	174,562
	2,030,905	1,839,918
Commitments and contingencies (Notes 2 and 9):		
Liability for environmental restoration.	220,000	225,000
	$9,584,141	$9,427,635

The accompanying notes are an integral part of these financial statements

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

Consolidated Statements of Cash Flows

Increase (Decrease) in Cash

	In thousands of dollars		
For the year ended December 31,	1997	1996	1995
Cash flows from operating activities:			
Net income	$ 59,835	$ 110,390	$ 248,036
Adjustments to reconcile net income to net cash provided by operating activities:			
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes	-	67,364	-
PowerChoice charge	190,000	-	-
Depreciation and amortization	339,641	329,827	317,831
Electric margin recoverable	-	-	58,588
Amortization of nuclear fuel	25,241	38,077	34,295
Provision for deferred income taxes	(19,506)	(6,870)	114,917
Gain on sale of subsidiary	-	(15,025)	(11,257)
Unbilled revenues	(6,600)	21,471	(71,258)
Net accounts receivable	(118,939)	121,198	56,748
Materials and supplies	(1,306)	2,265	13,663
Accounts payable and accrued expenses	(11,175)	8,224	(47,048)
Accrued interest and taxes	4,180	(11,750)	(35,440)
Changes in other assets and liabilities	76,204	35,231	20,930
Net cash provided by operating activities	537,575	700,402	700,005
Cash flows from investing activities:			
Construction additions	(286,389)	(296,689)	(332,443)
Nuclear fuel	(4,368)	(55,360)	(13,361)
Less: Allowance for other funds used during construction	5,310	3,665	1,063
Acquisition of utility plant	(285,447)	(348,384)	(344,741)
Materials and supplies related to construction	1,042	8,362	3,346
Accounts payable and accrued expenses related to construction	(2,794)	2,056	(7,112)
Other investments	(115,533)	541	(115,818)
Proceeds from sale of subsidiary (net of cash sold)	-	14,600	161,087
Other	8,761	(8,786)	26,234
Net cash used in investing activities	(393,971)	(331,611)	(277,004)
Cash flows from financing activities:			
Proceeds from long-term debt	-	105,000	346,000
Redemption of preferred stock	(8,870)	(10,400)	(10,950)
Reductions of long-term debt	(44,600)	(244,341)	(73,415)
Net change in short-term debt	-	-	(416,750)
Dividends paid	(37,397)	(38,281)	(201,246)
Other	97	(8,846)	(7,495)
Net cash used in financing activities	(90,770)	(196,868)	(363,856)
Net increase in cash	52,834	171,923	59,145
Cash at beginning of year	325,398	153,475	94,330
Cash at end of year	$ 378,232	$ 325,398	$ 153,475
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$ 279,957	$ 286,497	$ 290,352
Income taxes	$ 82,331	$ 95,632	$ 47,378

The accompanying notes are an integral part of these financial statements

NOTE 1. Summary of Significant Accounting Policies

The Company is subject to regulation by the PSC and FERC with respect to its rates for service under a methodology which establishes prices based on the Company's cost. The Company's accounting policies conform to GAAP, including the accounting principles for rate-regulated entities with respect to the Company's nuclear, transmission, distribution and gas operations (regulated business), and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The Company discontinued the application of regulatory accounting principles to its fossil and hydro generation operations in 1996 (see Note 2). In order to be in conformity with GAAP, management is required to use estimates in the preparation of the Company's financial statements.

Principles of Consolidation: The consolidated financial statements include the Company and its wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated.

Utility Plant: The cost of additions to utility plant and replacements of retirement units of property are capitalized. Cost includes direct material, labor, overhead and AFC. Replacement of minor items of utility plant and the cost of current repairs and maintenance is charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. The discontinuation of SFAS No. 71 did not affect the carrying value of the Company's utility plant.

Allowance for Funds Used During Construction: The Company capitalizes AFC in amounts equivalent to the cost of funds devoted to plant under construction for its regulated business. AFC rates are determined in accordance with FERC and PSC regulations. The AFC rate in effect during 1997 was 9.28%. AFC is segregated into its two components, borrowed funds and other funds, and is reflected in the "Interest charges" and the "Other income" sections, respectively, of the Consolidated Statements of Income. The amount of AFC credits recorded in each of the three years ended December 31, in thousands of dollars, was as follows:

	1997	1996	1995
Other income	$5,310	$3,665	$1,063
Interest charges	4,396	3,690	7,987

As a result of the discontinued application of SFAS No. 71 to the fossil and hydro operations, the Company capitalizes interest cost associated with the construction of fossil/hydro assets.

Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs: For accounting and regulatory purposes, depreciation is computed on the straight-line basis using the license lives for nuclear and hydro classes of depreciable property and the average service lives for all other classes. The percentage relationship between the total provision for depreciation and average depreciable property was approximately 3% for the years 1995 through 1997. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation rates when necessary.

Estimated decommissioning costs (costs to remove a nuclear plant from service in the future) for the Company's Unit 1 and its share of Unit 2 are being accrued over the service lives of the units, recovered in rates through an annual allowance and currently charged to operations through depreciation. The Company expects to commence decommissioning of both units shortly after cessation of operations at Unit 2 (currently planned for 2026), using a method which removes or decontaminates the Units components promptly at that time. See Note 3 - "Nuclear Plant Decommissioning."

The FASB issued an exposure draft in February 1996 entitled "Accounting for Certain Liabilities Related to Closure or Removal Costs of Long-Lived Assets." The scope of the project includes certain plant decommissioning costs, including those for fossil, hydro and nuclear plants. If approved, a liability would be recognized, with a corresponding plant asset, whenever a legal or constructive obligation exists to perform dismantlement or removal activities. The Company currently recognizes the liability for nuclear decommissioning over the service life of the plant as an increase to accumulated depreciation and does not recognize the closure or removal obligation associated with its fossil and hydro plants. The Company's **PowerChoice** agreement provides for the recovery of nuclear decommissioning costs. As discussed in Note 2, the Company intends to sell its fossil and hydro generating assets through an auction process. To the extent the assets are sold, the effect of this exposure draft on the Company should be mitigated. However, the Company cannot predict the results of the auction. The adoption of the proposed standard is not expected to impact the cash flow from these assets. The FASB continues to discuss the issues addressed in the exposure draft, as well as the timing of its implementation.

Amortization of the cost of nuclear fuel is determined on the basis of the quantity of heat produced for the generation of electric energy. The cost of disposal of nuclear fuel, which presently is $.001 per KWh of net generation available for sale, is based upon a contract with the DOE. These costs are charged to operating expense and recovered from customers through base rates or through the fuel adjustment clause.

Revenues: Revenues are based on cycle billings rendered to certain customers monthly and others bi-monthly for energy consumed and not billed at the end of the fiscal year. At December 31, 1997 and 1996, approximately $8.6 million and $11.1 million, respectively, of unbilled electric revenues remained unrecognized in results of operations, are included in "Other liabilities." Under the Company's **PowerChoice** agreement, the amount of unrecognized electric unbilled revenue as of the **PowerChoice** implementation date will be netted against certain other regulatory assets and liabilities. Thereafter, changes in electric unbilled revenues will no longer be deferred. In 1995, the Company used $71.5 million of electric unbilled revenues to reduce the 1995 revenue requirement. At December 31, 1997 and 1996, $34.7 million and $38.8 million, respectively, of unbilled gas revenues remain unrecognized in results of operations and may be used to reduce future gas revenue requirements. The unbilled revenues included in accounts receivable at December 31, 1997 and 1996, were $211.9 million and $218.5 million, respectively.

The Company's tariffs include electric and gas adjustment clauses under which energy and purchased gas costs, respectively, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company, as authorized by the PSC, charges operations for energy and purchased gas cost increases in the period of recovery. The PSC has periodically authorized the Company to make changes in the level of allowed energy and purchased gas costs included in approved rate schedules. As a result of such periodic changes, a portion of energy costs deferred at the time of change would not be recovered or may be overrecovered under the normal operation of the electric and gas adjustment clauses. However, the Company has to date been permitted to defer and bill or credit such portions to customers, through the electric and gas adjustment clauses, over a specified period of time from the effective date of each change.

The Company's electric FAC provides for partial pass-through of fuel and purchased power cost fluctuations from amounts forecast, with the Company absorbing a portion of increases or retaining a portion of decreases up to a maximum of $15 million per rate year. Thereafter, 100% of the fluctuation is passed on to ratepayers. The Company also shares with ratepayers fluctuations from amounts forecast for net resale margin and transmission benefits, with the Company retaining/absorbing 40% and passing 60% through to ratepayers. The amounts retained or absorbed in 1995 through 1997 were not material. Under the **PowerChoice** agreement, the FAC will be discontinued.

In December 1996, the Company, Multiple Intervenors and the PSC staff reached a three year gas settlement that was conditionally approved by the PSC. The agreement eliminated the gas adjustment clause and established a gas commodity cost adjustment clause ("CCAC"). The Company's gas CCAC provides for the collection or passback of certain increases or decreases from the base commodity cost of gas. The maximum annual risk or benefit to the Company is $2.25 million. All savings and excess costs beyond that amount will flow to ratepayers. For a discussion of the ratemaking associated with non-commodity gas costs, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Other Federal and State Regulatory Initiatives - Multi-Year Gas Rate Settlement Agreement."

Federal Income Taxes: As directed by the PSC, the Company defers any amounts payable pursuant to the alternative minimum tax rules. Deferred investment tax credits are amortized over the useful life of the underlying property.

Statement of Cash Flows: The Company considers all highly liquid investments, purchased with a remaining maturity of three months or less, to be cash equivalents.

Earnings Per Share: Basic earnings per share ("EPS") is computed based on the weighted average number of common shares outstanding for the period. The number of options outstanding at December 31, 1997, 1996 and 1995 that could potentially dilute basic EPS, (but are considered antidilutive for each period because the options exercise price was greater than the average market price of common shares), is immaterial. Therefore, the calculation of both basic and dilutive EPS are the same for each period.

Reclassifications: Certain amounts from prior years have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1997 presentation.

Comprehensive Income: In June 1997, FASB issued SFAS No. 130. SFAS No. 130 establishes standards for reporting comprehensive income. Comprehensive income is the change in the equity of a company, not including those changes that result from shareholder transactions. All components of comprehensive income are required to be reported in a new financial statement that is displayed with equal prominence as existing financial statements. The Company will be required to adopt SFAS No. 130 on January 1, 1998. The Company does not expect that adoption of SFAS No. 130 will have a significant impact on its reporting and disclosure requirements.

Segment Disclosures: Also in June 1997, FASB issued SFAS No. 131. SFAS No. 131 establishes standards for additional disclosure about operating segments for interim and annual financial statements. More specifically, it requires financial information to be disclosed for segments whose operating results are reviewed by the chief operating officer for decisions on resource allocation. It also requires related disclosures about product and services, geographic areas and major customers. The Company will be required to adopt SFAS No. 131 for the fiscal year ending December 31, 1998. The Company does not expect that the adoption of SFAS No. 131 will have a significant impact on its reporting and disclosure requirements.

Pension and Other Postretirement Benefits: In February 1998, FASB issued SFAS No. 132. SFAS No. 132 revises employers' disclosures about pension and other postretirement benefit plans. It does not change the measurement or recognition of those plans. It standardizes the disclosure requirements for pensions and other postretirement benefits to the extent practicable and requires additional information on changes in the benefit obligations and fair values of plan assets. The Company will be required to adopt SFAS No. 132 for the fiscal year ending December 31, 1998. The Company does not expect the adoption of SFAS No. 132 will have a significant impact on its reporting and disclosure requirements.

NOTE 2. Rate and Regulatory Issues and Contingencies

The Company's financial statements conform to GAAP, including the accounting principles for rate-regulated entities with respect to its regulated operations. Substantively, these principles permit a public utility, regulated on a cost-of-service basis, to defer certain costs which would otherwise be charged to expense, when authorized to do so by the regulator. These deferred costs are known as regulatory assets, which in the case of the Company are approximately $937 million, net of approximately $240 million of regulatory liabilities at December 31, 1997. These regulatory assets are probable of recovery. The portion of the $937 million which has been allocated to the nuclear generation and electric transmission and distribution business is approximately $810 million, which is net of approximately $240 million of regulatory liabilities. Regulatory assets allocated to the rate-regulated gas distribution business are $127 million. Generally, regulatory assets and liabilities were allocated to the portion of the business that incurred the underlying transaction that resulted in the recognition of the regulatory asset or liability. The allocation methods used between electric and gas are consistent with those used in prior regulatory proceedings.

The Company concluded as of December 31, 1996 that the termination, restatement or amendment of IPP contracts and implementation of PowerChoice was the probable outcome of negotiations that had taken place since the PowerChoice announcement. Under PowerChoice, the separated non-nuclear generation business would no longer be rate-regulated on a cost-of-service basis and, accordingly, regulatory assets related to the non-nuclear power generation business, amounting to approximately $103.6 million ($67.4 million after tax or 47 cents per share) was charged against 1996 income as an extraordinary non-cash charge.

The PSC in its written order issued March 20, 1998 approving PowerChoice, determined to limit the estimated value of the MRA regulatory asset that can be recovered from customers to approximately $4,000 million. The ultimate amount of the regulatory asset to be established may vary based on certain events related to the closing of the MRA. The estimated value of the MRA regulatory asset includes the issuance of 42.9 million shares of common stock, which the PSC in determining the recoverable amount of such asset, valued at $8 per share. Because the value of the consideration to be paid to the IPP Parties can only be determined at the MRA closing, the value of the limitation on the recoverability of the MRA regulatory asset has been estimated at $190 million (85 cents per share) which has been charged to 1997 earnings. The charge to expense was determined as the difference between $8 per share and the Company's closing common stock price on March 26, 1998 of $12 7/16 per share, multiplied by 42.9 million shares. Any variance from the estimate used in determining the charge to expense in 1997, including changes to the common stock price at closing, will be reflected in results of operations in 1998.

Under PowerChoice, the Company's remaining electric business (nuclear generation and electric transmission and distribution business) will continue to be rate-regulated on a cost-of-service basis and, accordingly, the Company continues to apply SFAS No. 71 to these businesses. Also, the Company's IPP contracts, including those restructured under the MRA and those not so restructured will continue to be the obligations of the regulated business.

SFAS No. 71 does not require the Company to earn a return on the regulatory assets in assessing its applicability. The Company believes that the prices it will charge for electric service over 10 years, including the CTC, assuming no reduction in demand or bypass of the CTC or exit fees, will be sufficient to recover the MRA regulatory asset and to provide recovery of and a return on the remainder of its assets, as appropriate. In the event the Company could no longer apply SFAS No. 71 in the future, it would be required to record an after-tax non-cash charge against income for any remaining unamortized regulatory assets and liabilities. Depending on when SFAS No. 71 was required to be discontinued, such charge would likely be material to the Company's reported financial condition and results of operations and the Company's ability to pay dividends. The PowerChoice agreement, while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.

The EITF of the FASB reached a consensus on Issue No. 97-4 "Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101" in July 1997. As discussed previously, the Company discontinued the application of SFAS No. 71 and applied SFAS No. 101 with respect to the fossil and hydro generation business at December 31, 1996, in a manner consistent with the EITF consensus.

With the implementation of PowerChoice, specifically the separation of non-nuclear generation as an entity that would no longer be cost-of-service regulated, the Company is required to assess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. SFAS No. 121 requires long-lived assets and certain identifiable intangibles held and used by an entity to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable or when assets are to be disposed of. In performing the review for recoverability, the Company is required to estimate future undiscounted cash flows expected to result from the use of the asset and/or its disposition. The Company has determined that there is no impairment of its fossil and hydro generating assets. To the extent the proceeds resulting from the sale of the fossil and hydro assets are not sufficient to avoid a loss, the Company would be able to recover such loss through the CTC. The PowerChoice agreement provides for deferral and future recovery of losses, if any, resulting from the sale of the non-nuclear generating assets. The Company's fossil and hydro generation plant assets had a net book value of approximately $1.1 billion at December 31, 1997.

As described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement," the conclusion of the termination, restatement or amendment of IPP contracts, and closing of the financing necessary to implement such termination, restatement or amendment, as well as implementation of PowerChoice, is subject to a number of contingencies. In the event the Company is unable to successfully bring these events to conclusion, it is likely that application of SFAS No. 71 would be discontinued. The resulting non-cash after-tax charges against income, based on regulatory assets and liabilities associated with the nuclear generation and electric transmission and distribution businesses as of December 31, 1997, would be approximately $526.5 million or $3.65 per share. Various requirements under applicable law and regulations and under corporate instruments, including those with respect to issuance of debt and equity securities, payment of common and preferred dividends and certain types of transfers of assets could be adversely impacted by any such write-downs.

The Company has recorded the following regulatory assets on its Consolidated Balance Sheets reflecting the rate actions of its regulators:

Regulatory tax asset represents the expected future recovery from ratepayers of the tax consequences of temporary differences between the recorded book bases and the tax bases of assets and liabilities. This amount is primarily timing differences related to depreciation. These amounts are amortized and recovered as the related temporary differences reverse. In January 1993, the PSC issued a Statement of Interim Policy on Accounting and Ratemaking Procedures that required adoption of SFAS No. 109 on a revenue-neutral basis.

Deferred finance charges represent the deferral of the discontinued portion of AFC related to CWIP at Unit 2 which was included in rate base. In 1985, pursuant to PSC authorization, the Company discontinued accruing AFC on CWIP for which a cash return was being allowed. This amount, which was accumulated in deferred debit and credit accounts up to the commercial operation date of Unit 2, awaits future disposition by the PSC. A portion of the deferred credit could be utilized to reduce future revenue requirements over a period shorter than the life of Unit 2, with a like amount of deferred debit amortized and recovered in rates over the remaining life of Unit 2. PowerChoice provides for netting, and thereby elimination of the debit and credit balances of deferred finance charges.

Deferred environmental restoration costs represent the Company's share of the estimated costs to investigate and perform certain remediation activities at both Company-owned sites and non-owned sites with which it may be associated. The Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. PowerChoice and the Company's gas settlement provide for the recovery of these costs over the settlement periods. The Company believes future costs, beyond the settlement periods, will continue to be recovered in rates. See Note 9 - "Environmental Contingencies."

Unamortized debt expense represents the costs to issue and redeem certain long-term debt securities which were retired prior to maturity. These amounts are amortized as interest expense ratably over the lives of the related issues in accordance with PSC directives.

Postretirement benefits other than pensions represent the excess of such costs recognized in accordance with SFAS No. 106 over the amount received in rates. In accordance with the PSC policy statement, postretirement benefit costs other than pensions are being phased-in to rates over a five-year period and amounts deferred will be amortized and recovered over a period not to exceed 20 years.

Substantially all of the Company's regulatory assets described above are being amortized to expense and recovered in rates over periods approved in the Company's electric and gas rate cases, respectively.

NOTE 3. Nuclear Operations

Nuclear Plant Decommissioning: The Company's site specific cost estimates for decommissioning Unit 1 and its ownership interest in Unit 2 at December 31, 1997 are as follows:

	Unit 1	Unit 2
Site Study (year)	1995	1995
End of Plant Life (year)	2009	2026
Radioactive Dismantlement to Begin (year)	2026	2028
Method of Decommissioning	Delayed Dismantlement	Immediate Dismantlement
Cost of Decommissioning (in January 1998 dollars)		In millions of dollars
Radioactive Components	$481	$201
Non-radioactive Components	117	48
Fuel Dry Storage/Continuing Care	78	43
	$676	$292

The Company estimates that by the time decommissioning is completed, the above costs will ultimately amount to $1.7 billion and $.9 billion for Unit 1 and Unit 2, respectively, using approximately 3.5% as an annual inflation factor.

In addition to the costs mentioned above, the Company expects to incur post-shutdown costs for plant rampdown, insurance and property taxes. In 1998 dollars, these costs are expected to amount to $119 million and $63 million for Unit 1 and the Company's share of Unit 2, respectively. The amounts will escalate to $210 million and $190 million for Unit 1 and the Company's share of Unit 2, respectively, by the time decommissioning is completed. In 1997, the Company made adjustments to the cash flow assumptions at Unit 1 for fuel dry storage, radioactive cost components, property tax and insurance, to more accurately reflect the estimated cost of each cost component. The revisions reduced the total cost estimate by approximately $10 million (in 1998 dollars).

NRC regulations require owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning radioactive portions of nuclear facilities and establish minimum amounts that must be available in such a trust at the time of decommissioning. The annual allowance for Unit 1 and the Company's share of Unit 2 was approximately $23.7 million, for each of the three years ended December 31, 1997. The amount was based upon the 1993 NRC minimum decommissioning cost requirements of $437 million and $198 million (in 1998 dollars) for Unit 1 and the Company's share of Unit 2, respectively. In Opinion No. 95-21, the Company was authorized, until the PSC orders otherwise, to continue to fund to the NRC minimum requirements. PowerChoice permits rate recovery for all radioactive and non-radioactive cost components for both units, including post-shutdown costs, based upon the amounts estimated in the 1995 site specific studies described above, which are higher than the NRC minimum. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. The Company believes that if decommissioning costs are higher than currently estimated, the costs would ultimately be included in the rate process.

Decommissioning costs recovered in rates are reflected in "Accumulated depreciation and amortization" on the balance sheet and amount to $266.8 million and $217.7 million at December 31, 1997 and 1996, respectively for both units. Additionally at December 31, 1997, the fair value of funds accumulated in the Company's external trusts were $164.7 million for Unit 1 and $51.0 million for its share of Unit 2. The trusts are included in "Other property and investments." Earnings on the external trust aggregated $40.3 million through December 31, 1997 and, because the earnings are available to fund decommissioning, have also been included in "Accumulated depreciation and amortization." Amounts recovered for non-radioactive dismantlement are accumulated in an internal reserve fund which has an accumulated balance of $45.2 million at December 31, 1997.

NRC Policy Statement and Proposal. The NRC issued a policy statement on the Restructuring and Economic Deregulation of the Electric Utility Industry (the "Policy Statement") in 1997. The Policy Statement addresses the NRC's concerns about the adequacy of decommissioning funds and about the potential impact on operational safety. Current NRC regulations allow a utility to set aside decommissioning funds annually over the estimated life of a plant. The Policy Statement declares the NRC will:

- Continue to conduct reviews of financial qualifications, decommissioning funding and antitrust requirements of nuclear power plants;
- Establish and maintain working relationships with state and federal rate regulators;
- Identify all nuclear power plant owners, indirect as well as direct; and
- Re-evaluate the adequacy of current regulations in light of economic and other changes resulting from rate deregulation.

In addition to the above Policy Statement, the NRC is proposing to amend its regulations on decommissioning funding to reflect conditions expected from deregulation of the electric power industry. The amended rule would:

- Revise the definition of an "electric utility" to reflect changes caused by restructuring within the industry.
- Define a "Federal licensee" as any licensee which has the full faith and credit backing of the United States government. Only such licensees could use statements of intent to meet decommissioning financial assurance requirements for power reactors.
- Require nuclear.power plant licensees to report to the NRC on the status of their decommissioning funds at least once every three years and annually within five years of the planned end of operation. NRC's present rule contains no such requirement because State and Federal rate-regulating bodies actively monitor these funds. A deregulated nuclear utility would have no such monitoring.
- Permit nuclear licensees to take credit on earnings for prepaid decommissioning trust funds and external sinking funds from the time the funds are set aside through the end of the decommissioning period. The present rule does not permit such credit because it assumed that inflation and taxes would erode any investment return. NRC has decided, however, that this position is not borne out by historical performance of inflation-adjusted funds invested in U.S. Treasury instruments.

The Company is unable to predict the outcome of this matter.

PSC Staff's Tentative Conclusions on the Future of Nuclear Generation: On August 27, 1997, the PSC requested comments on its staff's tentative conclusions about how nuclear generation and fossil generation should be treated after decisions are made on the individual electric restructuring agreements currently pending before the PSC. The PSC staff concluded that beyond the transition period (the period covered by the various New York utility restructuring agreements, including PowerChoice), nuclear generation should operate on a competitive basis. In addition, the PSC staff concluded that a sale of generation plants to third parties is the preferred means of determining the fair market value of generation plants and offers the greatest potential for the mitigation of stranded costs. The PSC staff also concluded that recovery of sunk costs, including post shutdown costs, would be subject to review by the PSC and this process should take into account mitigation measures taken by the utility, including the steps it has taken to encourage competition in its service area.

In October 1997, the majority of utilities with interests in nuclear power plants, including the Company, requested that the PSC reconsider its staff's nuclear proposal. In addition, the utilities raised the following issues: impediments to nuclear plants operating in a competitive mode; impediments to the sale of plants; responsibility for decommissioning and disposal of spent fuel; safety and health concerns; and environmental and fuel diversity benefits. In light of all of these issues, the utilities recommended that a more formal process be developed to address those issues.

The three investor-owned utilities, Rochester Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. and the Company, which are currently pursuing formation of a nuclear operating company in New York State, also filed a response with the PSC in October 1997. The response stated that a forced divestiture of the nuclear plants would add uncertainty to developing a statewide approach to operating the plants and requested that such a forced divestiture proposal be rescinded. The response also stated that implementation of a consolidated six-unit operation would contribute to the mitigation of unrecovered nuclear costs. NYPA, which is also pursuing formation of the nuclear operating company, submitted its own comments which were similar to the comments of the three utilities.

PowerChoice contemplates that the Company's nuclear plants will remain part of the Company's regulated business and that the Company will continue efforts to pursue a statewide solution such as the New York Nuclear Operating Company. The settlement stipulates that absent a statewide solution, the Company will file a detailed plan for analyzing proposed solutions for its nuclear assets, including the feasibility of an auction, transfer and/or divestiture within 24 months of **PowerChoice** approval. At December 31, 1997, the net book value of the Company's nuclear assets was approximately $1.5 billion, excluding the reserve for decommissioning.

Nuclear Liability Insurance: The Atomic Energy Act of 1954, as amended, requires the purchase of nuclear liability insurance from the Nuclear Insurance Pools in amounts as determined by the NRC. At the present time, the Company maintains the required $200 million of nuclear liability insurance.

With respect to a nuclear incident at a licensed reactor, the statutory limit for the protection of the public under the Price-Anderson Amendments Act of 1988 which is in excess of the $200 million of nuclear liability insurance, is currently $8.2 billion without the 5% surcharge discussed below. This limit would be funded by assessments of up to $75.5 million for each of the 110 presently licensed nuclear reactors in the United States, payable at a rate not to exceed $10 million per reactor per year. Such assessments are subject to periodic inflation indexing and to a 5% surcharge if funds prove insufficient to pay claims. With the 5% surcharge included, the statutory limit is $8.6 billion.

The Company's interest in Units 1 and 2 could expose it to a maximum potential loss, for each accident, of $111.8 million (with 5% assessment) through assessments of $14.1 million per year in the event of a serious nuclear accident at its own or another licensed U.S. commercial nuclear reactor. The amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations, whether or not a nuclear incident actually occurs.

Nuclear Property Insurance: The Nine Mile Point Nuclear Site has $500 million primary nuclear property insurance with the Nuclear Insurance Pools (ANI/MRP). In addition, there is $2.25 billion in excess of the $500 million primary nuclear insurance with Nuclear Electric Insurance Limited ("NEIL"). The total nuclear property insurance is $2.75 billion. NEIL also provides insurance coverage against the extra expense incurred in purchasing replacement power during prolonged accidental outages. The insurance provides coverage for outages for 156 weeks, after a 21-week waiting period. NEIL insurance is subject to retrospective premium adjustment under which the Company could be assessed up to approximately $11.3 million per loss.

Low Level Radioactive Waste: The Company currently uses the Barnwell, South Carolina waste disposal facility for low level radioactive waste; however, continued access to Barnwell is not assured and the Company has implemented a low level radioactive waste management program so that Unit 1 and Unit 2 are prepared to properly handle interim on-site storage of low level radioactive waste for at least a 10 year period.

Under the Federal Low Level Waste Policy Amendment Act of 1985, New York State was required by January 1, 1993 to have arranged for the disposal of all low level radioactive waste within the state or in the alternative, contracted for the disposal at a facility outside the state. To date, New York State has made no funding available to support siting for a disposal facility.

Nuclear Fuel Disposal Cost: In January 1983, the Nuclear Waste Policy Act of 1982 (the "Nuclear Waste Act") established a cost of $.001 per KWh of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until the year in which the Company initially plans to ship irradiated fuel to an approved DOE disposal facility. As of December 31, 1997, the Company has recorded a liability of $114.3 million for the disposal of nuclear fuel irradiated prior to 1983. Progress in developing the DOE facility has been slow and it is anticipated that the DOE facility will not be ready to accept deliveries until at least 2010. However, in July 1996, the United States Circuit Court of Appeals for the District of Columbia ruled that the DOE must begin accepting spent fuel from the nuclear industry by January 31, 1998 even though a permanent storage site will not be ready by then. The DOE did not appeal this decision. On January 31, 1997, the Company joined a number of other utilities, states, state agencies and regulatory commissions in filing a suit in the U.S. Court of Appeals for the District of Columbia against the DOE. The suit 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 fuel. On June 3, 1997, the DOE notified utilities that it likely will not meet its January 31, 1998 deadline and that the delay was unavoidable pursuant to the terms of the standard contract with DOE for fuel disposal. DOE also indicated it was not obligated to provide a financial remedy for such unavoidable delay. On November 14, 1997 the United States Court of Appeals for the District of Columbia Circuit issued a writ of mandamus precluding DOE from excusing its own delay on the grounds that it has not yet prepared a permanent repository or interim storage facility. On December 11, 1997, 27 utilities, including the Company, petitioned the DOE to suspend their future payments to the Nuclear Waste Fund until the DOE begins moving fuel from their plant sites. The petition further sought permission to escrow payments to the waste fund beginning in February 1998. On January 12, 1998, the DOE denied the petition. The Company is unable to determine the final outcome of this matter.

The Company has several alternatives under consideration to provide additional storage facilities, as necessary. Each alternative will likely require NRC approval, may require other regulatory approvals and would likely require incurring additional costs, which the Company has included in its decommissioning estimates for both Unit 1 and its share of Unit 2. The Company does not believe that the possible unavailability of the DOE disposal facility until 2010 will inhibit operation of either Unit.

NOTE 4. *Jointly-Owned Generating Facilities*

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1997. The Company is required to provide its respective share of financing for any additions to the facilities. Power output and related expenses are shared based on proportionate ownership. The Company's share of expenses associated with these facilities is included in the appropriate operating expenses in the Consolidated Statements of Income. Under PowerChoice, the Company will divest all of its fossil and hydro generation assets with a net book value of $1.1 billion, including its interests in jointly-owned facilities.

	Percentage Ownership	In thousands of dollars Utility Plant	Accumulated Depreciation	Construction Work in Progress
Roseton Steam Station Units No. 1 and 2 (a).	25	$ 96,110	$ 54,130	$ 432
Oswego Steam Station Unit No. 6 (b)	76	$ 270,316	$125,089	$ 39
Nine Mile Point Nuclear Station Unit No. 2 (c)	41	$1,507,721	$327,006	$6,748

(a) The remaining ownership interests are Central Hudson Gas and Electric Corporation ("Central Hudson"), the operator of the plant (35%), and Consolidated Edison Company of New York, Inc. (40%). Output of Roseton Units No. 1 and 2, which have a capability of 1,200,000 KW, is shared in the same proportions as the cotenants' respective ownership interests.

(b) The Company is the operator. The remaining ownership interest is Rochester Gas and Electric ("RG&E") (24%). Output of Oswego Unit No. 6, which has a capability of 850,000 KW, is shared in the same proportions as the cotenants' respective ownership interests.

(c) The Company is the operator. The remaining ownership interests are Long Island Lighting Company ("LILCO") (18%), New York State Electric & Gas Corporation ("NYSEG") (18%), RG&E (14%), and Central Hudson (9%). Output of Unit 2, which has a capability of 1,143,000 KW, is shared in the same proportions as the cotenants' respective ownership interests. In June 1997, LILCO and Long Island Power Authority ("LIPA") entered into an agreement, whereby, upon completion of certain transactions, LILCO's stock would be sold to LIPA. It is anticipated that LIPA would own LILCO's 18% ownership interest in Unit 2. In July 1997, the New York State Public Authorities Control Board unanimously approved the agreements related to the LIPA transaction, subject to certain conditions, and LILCO's stockholders subsequently approved this transaction.

5. Capitalization

AL STOCK

The Company is authorized to issue 185,000,000 shares of common stock, $1 par value; 3,400,000 shares of preferred stock, $100 par value; 19,600,000 shares of preferred stock, $25 par value; and 8,000,000 shares of preference stock, $25 par value. The table below summarizes changes in the capital stock issued and outstanding and the related capital accounts for 1995, 1996 and 1997:

	Common Stock $1 par value		Preferred Stock $100 par value			Preferred Stock $25 par value			
	Shares	Amount*	Shares	Non-Redeemable*	Redeemable*	Shares	Non-Redeemable*	Redeemable*	Capital Stock Premium and Expense (Net)*
December 31, 1994:	144,311,466	$144,311	2,376,000	$210,000	$27,600 (a)	12,774,005	$230,000	$89,350 (a)	$1,779,504
Issued	20,657	21	-	-	-	-	-	-	283
Redemptions			(18,000)	-	(1,800)	(366,000)	-	(9,150)	1,319
Foreign currency translation adjustment									3,141
December 31, 1995:	144,332,123	$144,332	2,358,000	$210,000	$25,800 (a)	12,408,005	$230,000	$80,200 (a)	$1,784,247
Issued	33,091	33	-	-	-	-	-	-	214
Redemptions			(18,000)	-	(1,800)	(344,000)	-	(8,600)	(28)
Foreign currency translation adjustment									(708)
December 31, 1996:	144,365,214	$144,365	2,340,000	$210,000	$24,000 (a)	12,064,005	$230,000	$71,600 (a)	$1,783,725
Issued	54,137	54	-	-	-	-	-	-	426
Redemptions			(18,000)	-	(1,800)	(282,801)	-	(7,070)	104
Foreign currency translation adjustment									(4,567)
December 31, 1997:	144,419,351	$144,419	2,322,000	$210,000	$ 22,200 (a)	11,781,204	$230,000	$ 64,530 (a)	$1,779,688

* In thousands of dollars
(a) Includes sinking fund requirements due within one year.

The cumulative amount of foreign currency translation adjustment at December 31, 1997 was $(15,448).

NON-REDEEMABLE PREFERRED STOCK (Optionally Redeemable)

The Company had certain issues of preferred stock which provide for optional redemption at December 31, as follows:

		In thousands of dollars		Redemption price per share (Before adding accumulated dividends)
Series	Shares	1997	1996	
Preferred $100 par value:				
3.40%	200,000	$ 20,000	$ 20,000	$ 103.50
3.60%	350,000	35,000	35,000	104.85
3.90%	240,000	24,000	24,000	106.00
4.10%	210,000	21,000	21,000	102.00
4.85%	250,000	25,000	25,000	102.00
5.25%	200,000	20,000	20,000	102.00
6.10%	250,000	25,000	25,000	101.00
7.72%	400,000	40,000	40,000	102.36
Preferred $25 par value:				
9.50%	6,000,000	150,000	150,000	25.00 (a)
Adjustable Rate-				
Series A	1,200,000	30,000	30,000	25.00
Series C	2,000,000	50,000	50,000	25.00
		$440,000	$440,000	

(a) Not redeemable until 1999.

MANDATORILY REDEEMABLE PREFERRED STOCK

At December 31,. the Company had certain issues of preferred stock, as detailed below, which provide for mandatory and optional redemption. These series require mandatory sinking funds for annual redemption and provide optional sinking funds through which the Company may redeem, at par, a like amount of additional shares (limited to 120,000 shares of the 7.45% series). The option to redeem additional amounts is not cumulative. The Company's five year mandatory sinking fund redemption requirements for preferred stock, in thousands, for 1998 through 2002 are as follows: $10,120; $7,620; $7,620; $7,620 and $3,050, respectively. The aggregate preference of preferred shares upon involuntary liquidation of the Company is the aggregate par value of such shares, plus an amount equal to the dividends accumulated and unpaid on such shares to the date of payment whether or not earned or declared.

	Shares		In thousands of dollars		Redemption price per share (Before adding accumulated dividends)	
Series	1997	1996	1997	1996	1997	Eventual minimum
Preferred $100 par value:						
7.45%	222,000	240,000	$22,200	$24,000	$101.69	$100.00
Preferred $25 par value:						
7.85%	731,204	914,005	18,280	22,850	25.28	25.00
8.375%	100,000	200,000	2,500	5,000	25.00	25.00
Adjustable Rate-						
Series B	1,750,000	1,750,000	43,750	43,750	25.00	25.00
			86,730	95,600		
Less sinking fund requirements			10,120	8,870		
			$76,610	$86,730		

LONG-TERM DEBT

Long-term debt at December 31 consisted of the following:

Series	Due	In thousands of dollars 1997	1996
First mortgage bonds:			
6 1/4%	1997	$ -	$ 40,000
6 1/2%	1998	60,000	60,000
9 1/2%	2000	150,000	150,000
6 7/8%	2001	210,000	210,000
9 1/4%	2001	100,000	100,000
5 7/8%	2002	230,000	230,000
6 7/8%	2003	85,000	85,000
7 3/8%	2003	220,000	220,000
8%	2004	300,000	300,000
6 5/8%	2005	110,000	110,000
9 3/4%	2005	150,000	150,000
7 3/4%	2006	275,000	275,000
*6 5/8%	2013	45,600	45,600
9 1/2%	2021	150,000	150,000
8 3/4%	2022	150,000	150,000
8 1/2%	2023	165,000	165,000
7 7/8%	2024	210,000	210,000
*8 7/8%	2025	75,000	75,000
* 7.2%	2029	115,705	115,705
Total First Mortgage Bonds		2,801,305	2,841,305
Promissory notes:			
*Adjustable Rate Series due			
July 1, 2015		100,000	100,000
December 1, 2023		69,800	69,800
December 1, 2025		75,000	75,000
December 1, 2026		50,000	50,000
March 1, 2027		25,760	25,760
July 1, 2027		93,200	93,200
Term Loan Agreement		105,000	105,000
Unsecured notes payable:			
Medium Term Notes, Various rates, due 2000-2004		20,000	20,000
Other		154,295	156,606
Unamortized premium (discount)		(9,884)	(10,708)
TOTAL LONG-TERM DEBT		3,484,476	3,525,963
Less long-term debt due within one year		67,095	48,084
		$3,417,381	$3,477,879

*Tax-exempt pollution control related issues

Several series of First Mortgage Bonds and Promissory Notes were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $414 million of such securities bear interest at a daily adjustable interest rate (with a Company option to convert to other rates, including a fixed interest rate which would require the Company to issue First Mortgage Bonds to secure the debt) which averaged 3.63% for 1997 and 3.46% for 1996 and are supported by bank direct pay letters of credit. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generating facilities or to refund outstanding tax-exempt bonds and notes (see Note 6).

Other long-term debt in 1997 consists of obligations under capital leases of approximately $29.7 million, a liability to the DOE for nuclear fuel disposal of approximately $114.3 million and a liability for IPP contract terminations of approximately $10.3 million. The aggregate maturities of long-term debt for the five years subsequent to December 31, 1997, excluding capital leases, in millions, are approximately $64, $108, $158, $310 and $230 respectively. The Company's aggregate maturities will increase significantly upon closing of the MRA. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement."

NOTE 6. Bank Credit Arrangements

The Company has an $804 million senior debt facility with a bank group consisting of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA discussed in Note 5. As of December 31, 1997, the amount outstanding under the senior debt facility was $529 million, consisting of $105 million under the term loan facility and a $424 million letter of credit, leaving the Company with $275 million of borrowing capability under the facility. The facility expires on June 30, 1999 (subject to earlier termination if the Company separates its fossil/hydro generation business from its transmission and distribution business, or any other significant restructuring plan). The interest rate applicable to the facility is variable based on certain rate options available under the agreement and currently approximates 7.7% (but capped at 15%). The Company is currently negotiating with the lenders to replace the senior debt facility with a larger facility to finance part of the MRA. The Company did not have any short-term debt outstanding at December 31, 1997 and 1996.

NOTE 7. Federal and Foreign Income Taxes

See Note 9 - "Tax Assessments."

Components of United States and foreign income before income taxes:

	In thousands of dollars 1997	1996	1995
United States	$125,027	$269,128	$400,087
Foreign	(1,621)	28,522	17,609
Consolidating eliminations	(3,476)	(17,402)	(10,267)
Income before extraordinary item and income taxes	$119,930	$280,248	$407,429

Following is a summary of the components of Federal and foreign income tax and a reconciliation between the amount of Federal income tax expense reported in the Consolidated Statements of Income and the computed amount at the statutory tax rate:

		In thousands of dollars 1997	1996*	1995
Components of Federal and foreign income taxes:				
Current tax expense:	Federal	$ 77,565	$ 96,011	$ 67,366
	Foreign	-	3,708	3,900
		77,565	99,719	71,266
Deferred tax expense:	Federal	(18,664)	382	84,002
	Foreign	1,194	2,393	4,125
		(17,470)	2,775	88,127
Total		$ 60,095	$102,494	$159,393
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:				
Computed tax		$ 41,975	$ 98,087	$142,601
Increase (reduction) attributable to flow-through of certain tax adjustments:				
Depreciation		36,411	28,103	31,033
Cost of removal		(8,168)	(8,849)	(9,247)
Deferred investment tax credit amortization		(7,454)	(8,018)	(8,589)
Other		(2,669)	(6,829)	3,595
		18,120	4,407	16,792
Federal and foreign income taxes		$ 60,095	$102,494	$159,393

At December 31, the deferred tax liabilities (assets) were comprised of the following:

	In thousands of dollars 1997	1996
PowerChoice charge	$ (66,500)	$ -
Alternative minimum tax	(17,448)	(64,313)
Unbilled revenue	(88,859)	(83,577)
Other	(247,438)	(237,850)
Total deferred tax assets	(420,245)	(385,740)
Depreciation related	1,358,827	1,421,550
Investment tax credit related	79,858	84,294
Other	302,092	237,414
Total deferred tax liabilities	1,740,777	1,743,258
Accumulated deferred income taxes	$1,320,532	$1,357,518

* Does not include the deferred tax benefit of $36,273 in 1996 associated with the extraordinary item for the discontinuance of regulatory accounting principles.

NOTE 8. Pension and Other Retirement Plans

The Company and certain of its subsidiaries have non-contributory, defined-benefit pension plans covering substantially all their employees. Benefits are based on the employee's years of service and compensation level. The Company's general policy is to fund the pension costs accrued with consideration given to the maximum amount that can be deducted for Federal income tax purposes.

Net pension cost for 1997, 1996 and 1995 included the following components:

	In thousands of dollars		
	1997	1996	1995
Service cost - benefits earned during the period	$ 27,100	$ 25,000	$ 22,500
Interest cost on projected benefit obligation	75,200	71,700	73,000
Actual return on plan assets	(188,200)	(134,100)	(215,600)
Net amortization and deferral	100,400	55,700	140,300
Total pension cost (1)	$ 14,500	$ 18,300	$ 20,200

(1) $3.2 million for 1997, $3.8 million for 1996 and $4.1 million for 1995 was related to construction labor and, accordingly, was charged to construction projects.

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

	In thousands of dollars	
At December 31,	1997	1996
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$ 990,415	$ 803,202
Non-vested benefits	73,430	83,107
Accumulated benefit obligations	1,063,845	886,309
Additional amounts related to projected pay increases	108,583	141,472
Projected benefits obligation for service rendered to date	1,172,428	1,027,781
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	(1,304,338)	(1,159,822)
Plan assets in excess of projected benefit obligations	(131,910)	(132,041)
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	(19,446)	(22,005)
Unrecognized net gain from actual return on plan assets different from that assumed	265,100	219,680
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions amortized over 10 years	19,920	66,129
Prior service cost not yet recognized in net periodic pension cost	(50,473)	(49,651)
Pension liability included in the consolidated balance sheets	$ 83,191	$ 82,112
Principle Actuarial Assumptions (%):		
Discount Rate	7.00	7.50
Rate of increase in future compensation levels (plus merit increases)	2.50	2.50
Long-term rate of return on plan assets	9.25	9.25

In addition to providing pension benefits, the Company and its subsidiaries provide certain health care and life insurance benefits for active and retired employees and dependents. Under current policies, substantially all of the Company's employees may be eligible for continuation of some of these benefits upon normal or early retirement.

The Company accounts for the cost of these benefits in accordance with PSC policy requirements which comply with SFAS No. 106. The Company has established various trusts to fund its future postretirement benefit obligation. In 1997, 1996 and 1995, the Company made contributions to such trusts of approximately $13.5 million, $28.5 million and $53.1 million, respectively, which represent the amount received in rates and from cotenants.

Net postretirement benefit cost for 1997, 1996 and 1995 included the following components:

	In thousands of dollars		
	1997	1996	1995
Service cost - benefits attributed to service during the period	$12,300	$12,900	$12,600
Interest cost on accumulated benefit obligation	34,800	37,500	45,400
Actual return on plan assets.	(24,500)	(12,900)	(11,200)
Amortization of the transition obligation over 20 years	10,900	13,500	18,800
Net amortization.	9,500	6,000	14,600
Total postretirement benefit cost	$43,000	$57,000	$80,200

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

	In thousands of dollars	
At December 31,	1997	1996
Actuarial present value of accumulated benefit obligations:		
Retired and surviving spouses	$392,832	$370,259
Active eligible	43,299	31,030
Active ineligible	83,720	69,441
Accumulated benefit obligation	519,851	470,730
Plan assets at fair value, consisting primarily of listed stocks, bonds and other fixed obligations	(181,101)	(143,071)
Accumulated postretirement benefit obligation in excess of plan assets . .	338,750	327,659
Unrecognized net loss from past experience different from that assumed and effects of changes in assumptions	(48,466)	(36,048)
Prior service cost not yet recognized in postretirement benefit cost . . .	30,086	39,205
Unrecognized transition obligation being amortized over 20 years	(163,350)	(174,240)
Accrued postretirement benefit liability included in the consolidated balance sheet	$157,020	$156,576

Principal actuarial assumptions (%):		
Discount rate	7.00	7.50
Long-term rate of return on plan assets	9.25	8.00
Health care cost trend rate:		
Pre-65.	7.00	8.00
Post-65	6.00	6.50

During 1996, the Company changed the eligibility requirements for plan benefits for employees who retire after May 1, 1996. Generally, plan benefits are now accrued for eligible participants beginning after age 45. Previous to this change, the Company accrued these benefits over the employees' service life. The effect of this change resulted in a decrease in the accumulated benefit obligation for active ineligible employees.

At December 31, 1997, the assumed health cost trend rates gradually decline to 5.0% in 2001. If the health care cost trend rate was increased by one percent, the accumulated postretirement benefit obligation as of December 31, 1997 would increase by approximately 6.7% and the aggregate of the service and interest cost component of net periodic postretirement benefit cost for the year would increase by approximately 5.8%.

The Company recognizes the obligation to provide postemployment benefits if the obligation is attributable to employees' past services, rights to those benefits are vested, payment is probable and the amount of the benefits can be reasonably estimated. At December 31, 1997 and 1996, the Company's postemployment benefit obligation is approximately $13.3 million and $13 million, respectively.

NOTE 9. Commitments and Contingencies

See Note 2.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1998, the Company had long-term contracts to purchase electric power from the following generating facilities owned by NYPA:

Facility	Expiration date of contract	Purchased capacity in MW	Estimated annual capacity cost
Niagara - hydroelectric project	2007	951	$27,369,000
St. Lawrence - hydroelectric project. . .	2007	104	1,300,000
Blenheim-Gilboa - pumped storage generating station.	2002	270	7,500,000
		1,325	$36,169,000

The purchase capacities shown above are based on the contracts currently in effect. The estimated annual capacity costs are subject to price escalation and are exclusive of applicable energy charges. The total cost of purchases under these contracts and the recently cancelled contract with Fitzpatrick nuclear plant was approximately, in millions, $91.0, $93.3 and $92.5 for the years 1997, 1996 and 1995, respectively. In May 1997, the Company cancelled its commitment to purchase 110 MW of capacity from the Fitzpatrick facility. The Company continues to have a contract with Fitzpatrick to purchase for resale up to 46 MW of power for NYPA's economic development customers.

Under the requirements of PURPA, the Company is required to purchase power generated by IPPs, as defined therein. The Company has 141 PPAs with 148 facilities, of which 143 are on line, amounting to approximately 2,695 MW of capacity at December 31, 1997. Of this amount 2,382 MW is considered firm. The following table shows the payments for fixed and other capacity costs, and energy and related taxes the Company estimates it will be obligated to make under these contracts without giving effect to the MRA. The payments are subject to the tested capacity and availability of the facilities, scheduling and price escalation.

Year	(In thousands of dollars) Schedulable Fixed Costs Capacity	Other	Variable Costs Energy and Taxes	Total
1998	$247,740	$41,420	$ 906,590	$1,195,750
1999	252,130	42,450	943,720	1,238,300
2000	242,030	44,080	974,080	1,260,190
2001	244,620	45,650	1,042,380	1,332,650
2002	248,940	47,330	1,063,830	1,360,100

The capacity and other fixed costs relate to contracts with 11 facilities, where the Company is required to make capacity and other fixed payments, including payments when a facility is not operating but available for service. These 11 facilities account for approximately 774 MW of capacity, with contract lengths ranging from 20 to 35 years. The terms of these existing contracts allow the Company to schedule energy deliveries from the facilities and then pay for the energy delivered. The Company estimates the fixed payments under these contracts will aggregate to approximately $8 billion over their terms, using escalated contract rates. Contracts relating to the remaining facilities in service at December 31, 1997, require the Company to pay only when energy is delivered, except when the Company decides that it would be better to pay a particular project a reduced energy payment to have the project reduce its high priced energy deliveries as described below. The Company currently recovers schedulable capacity through base rates and energy payments, taxes and other schedulable fixed costs through the FAC. The Company paid approximately $1,106 million, $1,088 million and $980 million in 1997, 1996 and 1995 for 13,500,000 MWh, 13,800,000 MWh and 14,000,000 MWh, respectively, of electric power under all IPP contracts.

On July 9, 1997, the Company announced the MRA to terminate, restate or amend certain IPP power purchase contracts. As a result of negotiations, the MRA currently provides for the termination, restatement or amendment of 28 PPAs with 15 IPPs, in exchange for an aggregate of approximately $3,616 million in cash and 42.9 million shares of the Company's common stock and certain fixed price swap contracts. Under the terms of the MRA, the Company would terminate PPAs representing approximately 1,180 MW of capacity and restate contracts representing 583 MW of capacity. The restated contracts are structured to be in the form of financial swaps with fixed prices for the first two years changing to an indexed pricing formula thereafter. The contract quantities are fixed for the full ten year term of the contracts. The MRA also requires the Company to provide the IPP Parties with a number of fixed price swap contracts with a term of seven years beginning in 2003. The terms of the MRA have been and continue to be modified.

Since 1996, the Company has negotiated 2 long term and several limited term contract amendments whereby the Company can reduce the energy deliveries from the facilities. These reduced energy agreements resulted in a reduction of IPP deliveries of approximately 1,010,000 MWh and 984,000 MWh during 1997 and 1996, respectively.

Sale of Customer Receivables: The Company has established a single-purpose, wholly-owned financing subsidiary, NM Receivables Corp., whose business consists of the purchase and resale of an undivided interest in a designated pool of customer receivables, including accrued unbilled revenues. For receivables sold, the Company has retained collection and administrative responsibilities as agent for the purchaser. As collections reduce previously sold undivided interests, new receivables are customarily sold. NM Receivables Corp. has its own separate creditors which, upon liquidation of NM Receivables Corp., will be entitled to be satisfied out of its assets prior to any value becoming available to the Company. The sale of receivables are in fee simple for a reasonably equivalent value and are not secured loans. Some receivables have been contributed in the form of a capital contribution to NM Receivables Corp. in fee simple for reasonably equivalent value, and all receivables transferred to NM

Receivables Corp. are assets owned by NM Receivables Corp. in fee simple and are not available to pay the parent Company's creditors.

At December 31, 1997 and 1996, $144.1 and $250 million, respectively, of receivables had been sold by NM Receivables, Corp. to a third party. The undivided interest in the designated pool of receivables was sold with limited recourse. The agreement provides for a formula based loss reserve pursuant to which additional customer receivables are assigned to the purchaser to protect against bad debts. At December 31, 1997, the amount of additional receivables assigned to the purchaser, as a loss reserve, was approximately $64.4 million. Although this represents the formula-based amount of credit exposure at December 31, 1997 under the agreement, historical losses have been substantially less.

To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser absorbs the excess. Concentrations of credit risk to the purchaser with respect to accounts receivable are limited due to the Company's large, diverse customer base within its service territory. The Company generally does not require collateral, i.e., customer deposits.

Tax Assessments: The Internal Revenue Service ("IRS") has conducted an examination of the Company's federal income tax returns for the years 1989 and 1990 and issued a Revenue Agents' Report. The IRS has raised an issue concerning the deductibility of payments made to IPPs in accordance with certain contracts that include a provision for a tracking account. A tracking account represents amounts that these mandated contracts required the Company to pay IPPs in excess of the Company's avoided costs, including a carrying charge. The IRS proposes to disallow a current deduction for amounts paid in excess of the avoided costs of the Company. Although the Company believes that any such disallowances for the years 1989 and 1990 will not have a material impact on its financial position or results of operations, it believes that a disallowance for these above-market payments for the years subsequent to 1990 could have a material adverse affect on its cash flows. To the extent that contracts involving tracking accounts are terminated or restated or amended under the MRA with IPP Parties as described in Note 2, the effects of any proposed disallowance would be mitigated with respect to the IPP Parties covered under the MRA. The Company is vigorously defending its position on this issue. The IRS is currently conducting its examination of the Company's federal income tax returns for the years 1991 through 1993.

Environmental Contingencies: The public utility industry typically utilizes and/or generates in its operations a broad range of hazardous and potentially hazardous wastes and by-products. The Company believes it is handling identified wastes and by-products in a manner consistent with federal, state and local requirements and has implemented an environmental audit program to identify any potential areas of concern and aid in compliance with such requirements. The Company is also currently conducting a program to investigate and restore, as necessary to meet current environmental standards, certain properties associated with its former gas manufacturing process and other properties which the Company has learned may be contaminated with industrial waste, as well as investigating identified industrial waste sites as to which it may be determined that the Company contributed. The Company has also been advised that various federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company is currently aware of 124 sites with which it has been or may be associated, including 76 which are Company-owned. The number of owned sites increased as the Company has established a program to identify and actively manage potential areas of concern at its electric substations. This effort resulted in identifying an additional 32 sites. With respect to non-owned sites, the Company may be required to contribute some proportionate share of remedial costs. Although one party can, as a matter of law, be held liable for all of the remedial costs at a site, regardless of fault, in practice costs are usually allocated among PRPs.

Investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) if necessary, determine the appropriate remedial actions and (3) where appropriate, identify other parties who should bear some or all of the cost of remediation. Legal action against such other parties will be initiated where appropriate. After site investigations are completed, the Company expects to determine site-specific remedial actions and to estimate the attendant costs for restoration. However, since investigations are ongoing for most sites, the estimated cost of remedial action is subject to change.

Estimates of the cost of remediation and post-remedial monitoring are based upon a variety of factors, including identified or potential contaminants; location, size and use of the site; proximity to sensitive resources; status of regulatory investigation and knowledge of activities and costs at similarly situated sites. Additionally, the Company's estimating process includes an initiative where these factors are developed and reviewed using direct input and support obtained from the DEC. Actual Company expenditures are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs, as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several. The Company has denied any responsibility at certain of these PRP sites and is contesting liability accordingly.

As a consequence of site characterizations and assessments completed to date and negotiations with PRPs, the Company has accrued a liability in the amount of $220 million, which is reflected in the Company's Consolidated Balance Sheets at December 31, 1997. The potential high end of the range is presently estimated at approximately $650 million, including approximately $285 million in the unlikely event the Company is required to assume 100% responsibility at non-owned sites. The amount accrued at December 31, 1997, incorporates the additional electric substations, previously mentioned, and a change in the method used to estimate the liability for 27 of the Company's largest sites to rely upon a decision analysis approach. This method includes developing several remediation approaches for each of the 27 sites, using the factors previously described, and then assigning a probability to each approach. The probability represents the Company's best estimate of the likelihood of the approach occurring using input received directly from the DEC. The probable costs for each approach are then calculated to arrive at an expected value. While this approach calculates a range of outcomes for each site, the Company has accrued the sum of the expected values for these sites. The amount accrued for the Company's remaining sites is determined through feasibility studies or engineering estimates, the Company's estimated share of a PRP allocation or where no better estimate is available, the low end of a range of possible outcomes. In addition, the Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. PowerChoice provides for the continued application of deferral accounting for cost differences resulting from this effort.

In October 1997, the Company submitted a draft feasibility study to the DEC, which included the Company's Harbor Point site and five surrounding non-owned sites. The study indicates a range of viable remedial approaches, however, a final determination has not been made concerning the remedial approach to be taken. This range consists of a low end of $22 million and a high end of $230 million, with an expected value calculation of $51 million, which is included in the amounts accrued at December 31, 1997. The range represents the total costs to remediate the properties and does not consider contributions from other PRPs. The Company anticipates receiving comments from the DEC on the draft feasibility study by the spring of 1999. At this time, the Company cannot definitively predict the nature of the DEC proposed remedial action plan or the range of remediation costs it will require. While the Company does not expect to be responsible for the entire cost to remediate these properties, it is not possible at this time to determine its share of the cost of remediation. In May 1995, the Company filed a complaint pursuant to applicable Federal and New York State law, in the U.S. District Court for the Northern District of New York against several defendants seeking recovery of past and future costs associated with the investigation and remediation of the Harbor Point and surrounding sites. In a motion currently pending before the court, the New York State Attorney General has moved to dismiss the Company's claims against the State of New York, the New York State Department of Transportation, the Thruway Authority and Canal Corporation. The Company has opposed this motion. The case management order presently calls for the close of discovery on December 31, 1998. As a result the Company cannot predict the outcome of the pending litigation against other

PRPs or the allocation of the Company's share of the costs to remediate the Harbor Point and surrounding sites.

Where appropriate, the Company has provided notices of insurance claims to carriers with respect to the investigation and remediation costs for manufactured gas plant, industrial waste sites and sites for which the Company has been identified as a PRP. To date, the Company has reached settlements with a number of insurance carriers, resulting in payments to the Company of approximately $36 million, net of costs incurred in pursuing recoveries. Under PowerChoice the electric portion or approximately $32 million will be amortized over 10 years. The remaining portion relates to the gas business and is being amortized over the three year settlement period.

Construction Program: The Company is committed to an ongoing construction program to assure delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1998 through 2002 will require approximately $1.4 billion, excluding AFC and nuclear fuel. For the years 1998 through 2002, the estimates, in millions, are $328, $269, $264, $275 and $300, respectively, which includes $26, $25, $22, $20 and $38, respectively, related to non-nuclear generation. The impact of the ice storm (see Note 13) on the construction program will not be known until restoration efforts have been completed. These amounts are reviewed by management as circumstances dictate.

Under **PowerChoice**, the Company will separate, through sale or spin-off, the Company's non-nuclear power generation business from the remainder of the business.

Gas Supply, Storage and Pipeline Commitments: In connection with its gas business, the Company has long-term commitments with a variety of suppliers and pipelines to purchase gas commodity, provide gas storage capability and transport gas commodity on interstate gas pipelines. The table below sets forth the Company's estimated commitments at December 31, 1997, for the next five years, and thereafter.

(In thousands of dollars)

Year	Gas Supply	Gas Storage/Pipeline
1998	$103,990	$95,720
1999	78,380	99,490
2000	56,110	81,550
2001	53,140	60,170
2002	39,860	26,610
Thereafter	155,560	71,130

With respect to firm gas supply commitments, the amounts are based upon volumes specified in the contracts giving consideration for the minimum take provisions. Commodity prices are based on New York Mercantile Exchange quotes and reservation charges, when applicable. For storage and pipeline capacity commitments, amounts are based upon volumes specified in the contracts, and represent demand charges priced at current filed tariffs.

At December 31, 1997, the Company's firm gas supply commitments extend through October 2006, while the gas storage and transportation commitments extend through October 2012. Beginning in May 1996, as a result of a generic rate proceeding, the Company was required to implement service unbundling, where customers could choose to buy natural gas from sources other than the Company. To date the migration has not resulted in any stranded costs since the PSC has allowed utilities to assign the pipeline capacity to the customers choosing another supplier. This assignment is allowed during a three-year period ending March 1999, at which time the PSC will decide on methods for dealing with the remaining unassigned or excess capacity. In September 1997, the PSC indicated that it is unlikely utilities will be allowed to continue to assign pipeline capacity to departing customers after March 1999. The Company is unable to predict how the PSC will resolve these issues.

NOTE 10. Fair Value of Financial and Derivative Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash and short-term investments: The carrying amount approximates fair value because of the short maturity of the financial instruments.

Long-term debt and mandatorily redeemable preferred stock: The fair value of fixed rate long-term debt and redeemable preferred stock is estimated using quoted market prices where available or discounting remaining cash flows at the Company's incremental borrowing rate. The carrying value of NYSERDA bonds and other long-term debt are considered to approximate fair value.

Derivative financial instruments: The fair value of futures and forward contracts are determined using quoted market prices and broker quotes.

The financial instruments held or issued by the Company are for purposes other than trading. The estimated fair values of the Company's financial instruments are as follows:

	In thousands of dollars			
At December 31,	1997		1996	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and short-term investments	$ 378,232	$ 378,232	$ 325,398	$ 325,398
Mandatorily redeemable preferred stock	86,730	87,328	95,600	86,516
Long-term debt: First Mortgage bonds	2,801,305	2,878,368	2,841,305	2,690,707
Medium-term notes	20,000	22,944	20,000	21,994
Promissory notes	413,760	413,760	413,760	413,760
Other	229,634	229,634	228,461	22[illegible]

In 1997, the Company's energy marketing subsidiary began to engage in both trading and non-trading activities generally using gas futures and electric and gas forward contracts. At December 31, 1997, for both trading and non-trading activities, the fair value of long and short positions was approximately $59.9 million and $57.6 million, respectively. These fair values exceed the weighted average fair value of open positions for the period ending December 31, 1997. The positions above extend for a period of less than one year. With respect to these activities the Company does not have any material counterparty credit risk at December 31, 1997.

Transactions entered into for trading purposes are accounted for on a mark-to-market basis with changes in fair value recognized as a gain or loss in the period of the change. At December 31, 1997, the open trading positions consisted of off-balance sheet electric and gas forward contracts. These positions consisted of long and short electric forward contracts with fair values of $45.3 million (1,878,000 MWh) and $44.3 million (1,778,000 MWh), respectively, and long and short gas forward contracts with fair values of $9.4 million (7.1 million Dth) and $10.2 million (7.3 million Dth), respectively. The quantities above represent notional contract quantities. The effects of trading activities on the Company's 1997 results of operations were not material.

Activities for non-trading purposes generally consist of transactions entered into to hedge the market fluctuations of contractual and anticipated commitments. Gas futures contracts are primarily used for hedging purposes. The change in fair value of these transactions are deferred until the gain or loss on the hedged item is recognized. The fair value of open positions for non-trading purposes at December 31, 1997, as well as the effect of these activities on the Company's results of operations for the same period ending, was not material.

The Company's investments in debt and equity securities consist of trust funds for the purpose of funding the nuclear decommissioning of Unit 1 and its share of Unit 2 (see Note 3 - "Nuclear Plant Decommissioning"), short-term investments held by Opinac Energy Corporation (a subsidiary) and a trust fund for certain pension benefits. The Company has classified all investments in debt and equity securities as available for sale and has recorded all such investments at their fair market value at December 31, 1997. The proceeds from the sale of investments were $159.7 million, $99.4 million and $70.3 million in 1997, 1996 and 1995, respectively. Net realized and unrealized gains and losses related to the nuclear decommissioning trust are reflected in "Accumulated depreciation and amortization" on the Consolidated Balance Sheets, which is consistent with the method used by the Company to account for the decommissioning costs recovered in rates. The unrealized gains and losses related to the investments held by Opinac Energy Corporation and the pension trust are included, net of tax, in "Common stockholders' equity" on the Consolidated Balance Sheets, while the realized gains and losses are included in "Other income and deductions" on the Consolidated Income Statements. The recorded fair values and cost basis of the Company's investments in debt and equity securities is as follows:

At December 31,	In thousands of dollars							
	1997				1996			
		Gross Unrealized				Gross Unrealized		
Security Type	Cost	Gain	(Loss)	Fair Value	Cost	Gain	(Loss)	Fair Value
U.S. Government Obligations.	$ 14,136	$ 1,864	$ (4)	$ 15,996	$ 24,782	$ 1,530	$ (33)	$ 26,279
Commercial Paper . .	106,035	1,542	-	107,577	90,495	739	-	91,234
Tax Exempt Obligations.	80,115	5,884	(55)	85,944	75,590	3,209	(147)	78,652
Corporate Obligations.	92,949	17,368	(830)	109,487	62,723	8,524	(422)	70,825
Other.	3,025	-	-	3,025	2,586	-	-	2,586
	$296,260	$26,658	$(889)	$322,029	$256,176	$14,002	$(602)	$269,576

Using the specific identification method to determine cost, the gross realized gains and gross realized losses were:

	In thousands of dollars		
Year Ended December 31,	1997	1996	1995
Realized gains.	$3,487	$2,121	$2,523
Realized losses	686	806	328

The contractual maturities of the Company's investments in debt securities is as follows:

	In thousands of dollars	
At December 31, 1997	Fair Value	Cost
Less than 1 year.	$106,677	$105,135
1 year to 5 years	10,845	10,654
5 years to 10 years	52,526	50,351
Due after 10 years.	113,946	104,353

NOTE 11. Stock Based Compensation

Under the Company's stock compensation plans, stock units and stock appreciation rights ("SARs") may be granted to officers, key employees and directors. In addition, the Company's plans allow for the grant of stock options to officers. In 1997, 1996 and 1995 the Company granted 209,918 units and 296,300 SARs, 291,228 units and 376,600 SARs and 169,500 units and 414,000 SARs, respectively. Also, in 1995 the Company granted 85,375 stock options. At December 31, 1997, there were 668,132 units, 1,086,900 SARs and 298,583 options outstanding. Stock units are payable in cash at the end of a defined vesting period, determined at the date of the grant, based upon the Company's stock price for a defined period. SARs become exercisable, as determined at the grant date, and are payable in cash based upon the increase in the Company's stock price from a specified level. As such, for these awards, compensation expense is recognized over the vesting period of the award based upon changes in the Company's stock price for that period. Options were granted over the period 1992 to 1995 and become exercisable three years and expire ten years from the grant date. These options are all considered to be antidilutive for EPS calculations. Included in the results of operations for the years ending 1997 and 1996, is approximately $3.2 and $2.6 million, respectively, related to these plans.

As permitted by SFAS No. 123 - "Accounting for Stock-Based Compensation" ("SFAS No. 123") the Company has elected to follow Accounting Principles Board Opinion No. 25-"Accounting for Stock Issued to Employees" (APB No. 25) and related interpretations in accounting for its employee stock options. Under APB No. 25, no compensation expense is recognized for stock options because the exercise price of the Company's employee stock options equals the market price of the underlying stock on the grant date. Since stock units and SARs are payable in cash, the accounting under APB No. 25 and SFAS No. 123 is the same. Therefore, the pro-forma disclosure of information regarding net income, as required by SFAS No. 123, relates only to the Company's outstanding stock options, the effect of which is immaterial to the financial statements for the years ended 1997, 1996 and 1995. There is no effect on earnings per share for these years resulting from the pro-forma adjustments to net income.

NOTE 12. Information Regarding the Electric and Gas Businesses

The Company is engaged principally in the business of production, purchase, transmission, distribution and sale of electricity and the purchase, distribution, sale and transportation of gas in New York State. The Company provides electric service to the public in an area of New York State having a total population of about 3,500,000, including among others, the cities of Buffalo, Syracuse, Albany, Utica, Schenectady, Niagara Falls, Watertown and Troy. The Company distributes or transports natural gas in areas of central, northern and eastern New York having a total population of about 1,700,000 nearly all within the Company's electric service area. Certain information regarding the Company's electric and natural gas segments is set forth in the following table. General corporate expenses, property common to both segments and depreciation of such common property have been allocated to the segments in accordance with the practice established for regulatory purposes. Identifiable assets include net utility plant, materials and supplies, deferred finance charges, deferred recoverable energy costs and certain other regulatory and other assets. Corporate assets consist of other property and investments, cash, accounts receivable, prepayments, unamortized debt expense and certain other regulatory and other assets. At December 31, 1997, total plant assets consisted of approximately 24% Nuclear, 20% Fossil/Hydro, 42% Transmission and Distribution, 11% Gas and 3% Common.

	In thousands of dollars		
	1997	1996	1995
Operating revenues:			
Electric	$3,309,441	$3,308,979	$3,335,548
Gas	656,963	681,674	581,790
Total	$3,966,404	$3,990,653	$3,917,338
Operating income:			
Electric	$ 462,240	$ 438,590	$ 587,282
Gas	96,599	83,748	96,752
Total	$ 558,839	$ 522,338	$ 684,034
Other Income and (deductions):			
Electric	$ (190,000)	$ -	$ -
Sub-total	368,839	522,338	684,034
Other income	24,997	35,943	3,069
Interest charges	(273,906)	(278,033)	(279,674)
Income before federal and foreign income taxes	$ 119,930	$ 280,248	$ 407,429
Federal and foreign income taxes:			
Electric	$ 30,090	$ 79,574	$ 133,246
Gas	30,005	22,920	26,147
Total	60,095	102,494	159,393
Income before extraordinary item	$ 59,835	$ 177,754	$ 248,036
Depreciation and amortization:			
Electric	$ 311,683	$ 302,825	$ 292,995
Gas	27,958	27,002	24,836
Total	$ 339,641	$ 329,827	$ 317,831
Construction expenditures (including nuclear fuel):			
Electric	$ 221,915	$ 277,505	$ 285,722
Gas	68,842	74,544	60,082
Total	$ 290,757	$ 352,049	$ 345,804
Identifiable assets:			
Electric	$7,257,163	$7,372,370	$7,592,287
Gas	1,185,001	1,203,184	1,123,045
Total	8,442,164	8,575,554	8,715,332
Corporate assets	1,141,977	852,081	762,537
Total assets	$9,584,141	$9,427,635	$9,477,869

Note 13. Subsequent Event

In early January 1998, a major ice storm and flooding caused extensive damage in a large area of northern New York. The Company's electric transmission and distribution facilities in an area of approximately 7,000 square miles were damaged, interrupting service to approximately 120,000 of the Company's customers, or approximately 300,000 people. The Company had to rebuild much of its transmission and distribution system to restore power in this area. By the end of January 1998, service to all customers was restored; however, the final costs of the storm will not be known as crews continue to make final repairs to temporary measures to restore service and salvage operations cannot be completed until spring.

The preliminary estimate of the total cost of the restoration and rebuild efforts could exceed $125 million. A portion of the cost will be capitalized; however, at this time, the Company is unable to determine the capital portion until rebuild efforts have been completed and all labor, material and other costs, including charges from other utilities and contractors, have been received and analyzed.

The Company is pursuing federal disaster relief assistance and is working with its insurance carriers to assess what portion of the rebuild costs are covered by insurance policies. The Company is also analyzing potential available options for state financial aid. The Company is unable to determine what recoveries, if any, it may receive from these sources.

Absent recovery, the Company would face a charge to earnings in the first quarter of 1998 to reflect its estimate of unrecoverable, non-capitalized costs.

NOTE 14. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income (loss) and earnings (loss) per common share by quarters from 1997, 1996 and 1995, respectively, are shown in the following table. The Company, in its opinion, has included all adjustments necessary for a fair presentation of the results of operations for the quarters. Due to the seasonal nature of the utility business, the annual amounts are not generated evenly by quarter during the year. The Company's quarterly results of operations reflect the seasonal nature of its business, with peak electric loads in summer and winter periods. Gas sales peak in the winter.

In thousands of dollars

Quarter Ended		Operating revenues	Operating income	Net income (loss)	Basic and Diluted Earnings (loss) per common share
December 31,	1997	$ 960,304	$ 86,024	$(115,619)	$ (.86)
	1996	971,106	117,832	(25,808)	(.24)
	1995	966,478	132,228	27,874	.13
September 30,	1997	$ 896,570	$110,174	$ 31,683	$ .15
	1996	895,713	47,119	(12,916)	(.16)
	1995	887,231	142,732	46,941	.26
June 30,	1997	$ 945,698	$130,704	$ 40,749	$ .22
	1996	960,771	142,755	52,992	.30
	1995	938,816	152,297	54,485	.31
March 31,	1997	$1,163,832	$231,937	$ 103,022	$ .65
	1996	1,163,063	214,632	96,122	.60
	1995	1,124,813	256,777	118,736	.75

In the fourth quarter of 1997 the Company wrote-off $190.0 million (85 cents per share) for the estimated amount of the MRA regulatory asset disallowed in rates by the PSC. In the fourth quarter of 1996 the Company recorded an extraordinary item for the discontinuance of regulatory accounting principles of $103.6 million (47 cents per common share). In the third quarter of 1996 the Company increased the allowance for doubtful accounts by $68.5 million (31 cents per common share). In the fourth quarter of 1995, the Company recorded $16.9 million (8 cents per common share) for MERIT earned in accordance with the 1991 Agreement.

ELECTRIC AND GAS STATISTICS

ELECTRIC CAPABILITY

	Thousands of KW			
December 31,	1997	%	1996	1995
Owned:				
Coal	1,360	16.7	1,333	1,316
Oil*	646	7.9	636	636
Dual Fuel - Oil/Gas	700	8.6	700	700
Nuclear	1,082	13.3	1,082	1,082
Hydro	661	8.1	617	665
	4,449	54.6	4,368	4,399
Purchased:				
New York Power Authority				
- Hydro	1,325	16.2	1,310	1,325
- Nuclear	-	-	110	110
IPPs	2,382	29.2	2,406	2,390
	3,707	45.4	3,826	3,825
Total capability **	8,156	100.0	8,194	8,224
Electric peak load	6,348		6,021	6,211

* In 1994, Oswego Unit No. 5 (an oil-fired unit with a capability of 850,000 KW) was put into long-term cold standby, but could be returned to service in three months.

** Available capability can be increased during heavy load periods by purchases from neighboring interconnected systems. Hydro station capability is based on average December stream-flow conditions.

ELECTRIC STATISTICS

	1997	1996	1995
Electric sales (Millions of KWh):			
Residential	9,905	10,109	10,055
Commercial	11,552	11,564	11,613
Industrial	7,191	7,148	7,061
Industrial-Special	4,507	4,326	4,053
Municipal service	235	246	229
Other electric systems	3,746	5,431	4,305
Subsidiary	-	303	368
	37,136	39,127	37,684
Electric revenues (Thousands of dollars):			
Residential	$1,227,245	$1,252,165	$1,214,848
Commercial	1,233,417	1,237,385	1,237,502
Industrial	531,164	524,858	523,996
Industrial-Special	61,820	58,444	56,250
Municipal service	54,545	53,795	50,860
Other electric systems	83,794	113,391	88,936
Miscellaneous	117,456	53,698	143,625
Subsidiary	-	15,243	19,531
	$3,309,441	$3,308,979	$3,335,548
Electric customers (Average):			
Residential	1,404,345	1,405,083	1,399,725
Commercial	146,039	145,149	144,731
Industrial	1,970	2,045	2,122
Industrial-Special	85	99	83
Other	1,519	1,302	1,488
Subsidiary	-	13,557	13,508
	1,553,958	1,567,235	1,561,657
Residential (Average):			
Annual KWh use per customer	7,053	7,195	7,184
Cost to customer per KWh	12.39¢	12.39¢	12.08¢
Annual revenue per customer	$873.89	$891.17	$867.92

GAS STATISTICS

	1997	1996	1995
Gas Sales (Thousands of Dth):			
Residential	55,203	56,728	51,842
Commercial	22,069	25,353	23,818
Industrial	1,381	2,770	2,660
Other gas systems	28	30	161
Total sales	78,681	84,881	78,481
Spot market	2,451	10,459	1,723
Transportation of customer-owned gas	152,813	134,671	144,613
Total gas delivered	233,945	230,011	224,817
Gas Revenues (Thousands of dollars):			
Residential	$436,136	$417,348	$368,391
Commercial	148,213	162,275	143,643
Industrial	6,549	13,325	11,530
Other gas systems	130	138	762
Spot market	6,346	37,124	3,096
Transportation of customer-owned gas	55,657	50,381	48,290
Miscellaneous	3,932	1,083	6,078
	$656,963	$681,674	$581,790
Gas Customers (Average):			
Residential	484,862	477,786	471,948
Commercial	40,955	41,266	40,945
Industrial	186	206	225
Other	6	6	1
Transportation	843	713	652
	526,852	519,977	513,771
Residential (Average):			
Annual dekatherm use per customer	113.9	118.7	109.8
Cost to customer per Dth.	$7.90	$7.36	$7.11
Annual revenue per customer	$899.51	$873.50	$780.58
Maximum day gas sendout (Dth)	1,133,370	1,152,996	1,211,252

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

The Company has nothing to report for this item.

PART III

Item 10. Directors and Executive Officers of the Registrant.

Business Background of Directors

CLASS I DIRECTORS - TERMS EXPIRING IN 1998

ALBERT J. BUDNEY, JR.
- President, Niagara Mohawk Power Corporation
- Director since 1995

Mr. Budney, age 50, was elected President of the Company in 1995. Mr. Budney was previously employed by UtiliCorp United, Inc., an energy services company, as Managing Vice President of the UtiliCorp Power Services Group and as President of the Missouri Public Service Division. Mr. Budney joined UtiliCorp United, Inc. in 1993. Prior to that, he was Vice President of Stone & Webster Engineering Corp., where he managed the engineering firm's Boston Business Development Department. Director of Plum Street Enterprises, Inc. ("Plum Street"); Canadian Niagara Power Company, Limited ("CNP"); and Utilities Mutual Insurance Company. President of Opinac North America, Inc. ("Opinac NA"), a wholly-owned subsidiary of the Company. Opinac NA holds 100% of Plum Street and, through its subsidiary, Opinac Energy Corporation ("Opinac"), a 50 percent interest in CNP.

EDMUND M. DAVIS
- Attorney
- Director since 1970
- Member of Compensation & Succession, Corporate Public Policy & Environmental Affairs, and Finance Committees of the Board

Mr. Davis, age 68, retired in 1995 as of counsel to Hiscock & Barclay, LLP, Syracuse, NY, Attorneys-at-Law. Mr. Davis was a partner and had been associated with the law firm since 1957.

DR. BONNIE GUITON HILL
- President and Chief Executive Officer of The Times Mirror Foundation and Vice President of The Times Mirror Company
- Director since 1991
- Member of Audit, Corporate Public Policy & Environmental Affairs, and Finance Committees of the Board

Dr. Hill, age 56, President and Chief Executive Officer of The Times Mirror Foundation, a non-profit institution, and Vice President of The Times Mirror Company, a news and information company, located in Los Angeles, CA. Dr. Hill served as Dean and Professor of Commerce of the McIntire School of Commerce at the University of Virginia from 1992-1996. Prior to that, she served as the Secretary of State and Consumer Services Agency for the State of California. Director of AK Steel Corporation; Crestar Financial Corporation; Hershey Foods Corporation; and Louisiana-Pacific Corporation.

HENRY A. PANASCI, JR.
- Chairman, Cygnus Management Group, LLC
- Director since 1988
- Member of Compensation & Succession, Corporate Public Policy and Environmental Affairs, and Finance Committees of the Board

Mr. Panasci, age 69, Chairman of Cygnus Management Group, LLC, a consulting firm specializing in venture capital and private investments located in Syracuse, NY. Mr. Panasci retired in 1996 as Chairman of the Board and Chief Executive Officer of Fay's Incorporated, a drug store chain. Mr. Panasci co-founded Fay's Drug Co., Inc., with his father, in 1958. Director of National Association of Chain Drug Stores.

CLASS II DIRECTORS - TERMS EXPIRING IN 1999

WILLIAM F. ALLYN
- President and Chief Executive Officer of Welch Allyn, Inc.
- Director since 1988
- Member of Audit, Compensation & Succession, and Nuclear Oversight Committees of the Board

Mr. Allyn, age 62, President and Chief Executive Officer of Welch Allyn, Inc., Skaneateles Falls, NY, a manufacturer of medical diagnostic instrumentation, bar code readers and optical scanning devices. Mr. Allyn joined Welch Allyn, Inc. in 1962 and was elected to his present position in 1980. Director of ONBANCorp., Inc.; OnBank & Trust Company; Oneida Limited; and Perfex Corporation.

WILLIAM E. DAVIS
- Chairman of the Board and Chief Executive Officer of the Company
- Director since 1992
- Chairperson of Executive Committee of the Board

Mr. Davis, age 55, was elected Chairman of the Board and Chief Executive Officer of the Company in 1993. Mr. Davis joined the Company in 1990 and was elected Senior Vice President in April 1992, serving in that capacity until elected Vice-Chairman of the Board of the Company in November 1992. Director of Opinac NA; Plum Street; Opinac; CNP; and Utilities Mutual Insurance Company. Mr. Davis is also the Chairman of the Board of Plum Street and holds the position of Secretary, Utilities Mutual Insurance Company.

WILLIAM J. DONLON
- Former Chairman of the Board and Chief Executive Officer of the Company
- Director since 1980

Mr. Donlon, age 68, retired in 1993 as Chairman of the Board and Chief Executive Officer of the Company with 45 years service as an active employee. Director of Opinac; ONBANCorp., Inc.; and OnBank & Trust Company.

ANTHONY H. GIOIA
- Chairman and Chief Executive Officer of Gioia Management, Inc.
- Director since 1996
- Member of Executive, Compensation & Succession, and Nuclear Oversight Committees of the Board

Mr. Gioia, age 56, Chairman and Chief Executive Officer of Gioia Management, Inc., a holding company for several companies, including three packaging companies located in Buffalo and Lockport, NY. Mr. Gioia has held his present position since 1987.

DR. PATTI McGILL PETERSON
- Executive Director of the Council for International Exchange of Scholars
- Director since 1988
- Member of Executive, Audit (Chairperson), and Corporate Public Policy & Environmental Affairs Committees of the Board

Dr. Peterson, age 54, Executive Director of the Council for International Exchange of Scholars, a non-profit organization located in Washington, DC. From 1996 to 1997, Dr. Peterson was a Senior Fellow of the Cornell Institute for Public Affairs, Cornell University, Ithaca, NY. Dr. Peterson also served as President of St. Lawrence University from 1987-1996. Prior to that, she was President of Wells College. She holds the title President Emerita at both institutions. Independent Trustee of John Hancock Mutual Funds.

CLASS III DIRECTORS - TERMS EXPIRING IN 2000

LAWRENCE BURKHARDT, III
- Nuclear Consultant
- Director since 1988
- Chairperson of Nuclear Oversight Committee of the Board

Mr. Burkhardt, age 65, independent consultant to the nuclear industry since 1990. Prior to his retirement in 1990, Mr. Burkhardt was employed by the Company and served as Executive Vice President of Nuclear Operations. Director of MACTEC, Inc., formerly Management Analysis Company.

DOUGLAS M. COSTLE
- Distinguished Senior Fellow and Chairman of the Board of the Institute for Sustainable Communities
- Director since 1991
- Member of Executive, Audit, Corporate Public Policy & Environmental Affairs (Chairperson), and Nuclear Oversight Committees of the Board

Mr. Costle, age 58, Distinguished Senior Fellow and Chairman of the Board of the Institute for Sustainable Communities, a non-profit organization located in Montpelier, VT. Mr. Costle has held his present position since 1991. Former Dean of the Vermont Law School in South Royalton, Vermont, and Administrator of the U.S. Environmental Protection Agency. Independent Trustee of John Hancock Mutual Funds.

DONALD B. RIEFLER
- Financial Market Consultant
- Director since 1978
- Member of Executive, Audit, Finance (Chairperson), and Nuclear Oversight Committees of the Board

Mr. Riefler, age 70, financial market consultant and advisor to J. P. Morgan, Florida FSB, Palm Beach, FL, a private banking concern affiliated with J. P. Morgan & Co., Inc. Prior to his retirement in 1991, Mr. Riefler was Chairman of the Market Risk Committee for J. P. Morgan & Co. Incorporated and Morgan Guaranty Trust Company of New York.

STEPHEN B. SCHWARTZ
- Retired Senior Vice President, International Business Machines Corporation
- Director since 1992

- Member of Executive, Compensation & Succession (Chairperson), and Finance Committees of the Board

Mr. Schwartz, age 63, retired as Senior Vice President of International Business Machines Corporation in 1992. Mr. Schwartz joined IBM in 1957 and was elected Senior Vice President in 1990. Director of MFRI, Inc.

The information regarding executive officers appears at the end of Part I of this Form 10-K Annual Report.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities and Exchange Act of 1934 requires the Company's directors, executive officers and beneficial owners of more than 10 percent of any class of equity securities or any other person subject to Section 16 ("reporting persons") to file initial reports of ownership and reports of changes in ownership of the Company's equity securities with the Securities and Exchange Commission and the New York Stock Exchange. Based solely on a review of the copies of such forms and written representations from the Company's directors and executive officers, the Company believes that during the preceding year the reporting persons have complied with all Section 16(a) filing requirements.

Item 11. Executive Compensation

BOARD OF DIRECTORS' COMPENSATION AND SUCCESSION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation and Succession Committee of the Board of Directors (the "Committee") is composed entirely of non-employee directors. The Committee has responsibility for recommending officer salaries and for the administration of the Company's officer incentive compensation plans as described in this report. The Committee makes recommendations to the Board of Directors which makes final officer compensation determinations.

This Committee report describes the Company's executive officer compensation policies, the components of the compensation program, and the manner in which 1997 compensation determinations were made for the Company's Chairman of the Board and Chief Executive Officer, Mr. William E. Davis.

The 1997 Executive Officer Compensation Program was composed entirely of base salary, frozen at 1995 levels, and 1997 grants of stock units and stock appreciation rights ("SARs") made pursuant to the Long-Term Incentive Plan adopted by the Board of Directors on September 25, 1996 (the "LTIP"), as described later in this report.

BASE SALARY

The Committee seeks to ensure that salaries of the Company's officers, including executive officers, remain competitive with levels paid to comparable positions among other U.S. electric and gas utilities with comparable revenues (collectively referred to as the "Comparator Utilities"). The Committee believes that competitive salaries provide the foundation of the Company's officer compensation program and are essential for the Company to attract and retain qualified officers, especially in light of the increasing competition within the industry. Each officer position has been assigned to a competitive salary range. The Committee intends to administer salaries within the 25th to 75th percentiles of practice with respect to those Comparator Utilities. The 1997 average salary of the five named executive officers falls below 25th percentile competitive levels. Since executive officer salaries were frozen at 1995 levels, as a condition for receipt of 1995 stock incentive grants, the competitiveness of annual executive officer compensation is heavily dependent on stock-related incentives in the form of stock units and stock appreciation rights granted under the 1995 Stock Incentive Plan ("SIP") and the LTIP.

1995 STOCK INCENTIVE PLAN

On December 14, 1995, the Board of Directors approved the SIP to promote the success and enhance the value of the Company through the retention and continued motivation of the Company's officers and to focus their efforts toward the execution of business strategies directed toward improving financial returns to shareholders. Awards under the SIP consisted of stock units and SARs. These stock unit grants will be paid in cash in 1998 based on the fair market value of the Company's common stock during the last 12 consecutive trading days in 1997 ($9.922). Under the SIP, dividends are credited (in an amount equivalent to dividends paid, if any, on the Company's common stock) with respect to all stock units granted. These credits are reinvested at the prevailing stock price, thereby increasing the number of stock units payable at the end of the period. No dividends were credited to SIP stock units. The SARs first became exercisable on January 2, 1998, and may be exercised until they expire on December 31, 2002.

The SIP was structured so that any compensation earned by officers during the two-year period 1996 and 1997, other than base salary, will be based on the Company's year-end 1997 stock price and total returns realized by shareholders during this period. Accordingly, participants (including the executive officers listed in the Summary Compensation Table) did not receive any salary increases (except to reflect promotions), annual incentive compensation payments or stock option grants during 1996 and 1997. Generally speaking, SIP grants were structured so that the Company's stock price would have to more than double during this two-year period in order for the total compensation of the participants to approximate median competitive levels.

The Committee does not intend to make further SIP grants other than the 1995 stock unit grants which became payable on December 31, 1997 and the 1995 stock appreciation rights grants which became exercisable on January 2, 1998 and expire on December 31, 2002. Long-term incentive grants were made in 1996, 1997, and 1998 under the LTIP described below.

LONG-TERM INCENTIVE PLAN

Because the Committee seeks to provide a continuous program of long-term stock incentives, on September 25, 1996 the Board of Directors adopted the LTIP and approved stock unit and SAR grants for the 1996-1998 period. These stock unit grants will be paid in cash in early 1999. Dividends are credited (in an amount equivalent to dividends paid, if any, on the Company's common stock) with respect to the 1996-1998 stock unit grants, which are reinvested at the prevailing stock price, thereby increasing the number of stock units payable in early 1999. The payment value of the stock units will be based on the average fair market value of the Company's common stock during the last 12 consecutive trading days in 1998. The 1996 LTIP SAR grants first become exercisable on January 2, 1999, and may be exercised until they expire on December 31, 2005.

On January 29, 1997, the Board of Directors approved the grant of LTIP stock units and SARs for the 1997-1999 performance period. These stock units, and accumulated dividend stock units, will be paid in early 2000 based on the average fair market value of the Company's common stock during the last twelve consecutive trading days in 1999. The SARs first become exercisable on January 2, 2000, and can be exercised until they expire on December 31, 2006.

The size of both the 1996-1998 and 1997-1999 LTIP stock unit and SAR grants were determined, based on the price of the Company's common stock at the time these grants were made, so that the combination of the officers' current salaries plus the grant date present value of SIP, and LTIP grants for the 1996-1998 and 1997-1999 performance periods, would approximate the 50th percentile of comparator utility total compensation practice for the three-year period 1995 through 1997. The competitiveness of the actual compensation realized from SIP and the 1996-1998 and 1997-1999 LTIP grants is dependent on the market value of the Company's common stock at the end of 1997, 1998, and 1999.

The Board of Directors also approved a January 19, 1998 grant of LTIP stock units and SARs for the period 1998-2000. These stock units, and any accumulated dividend stock units, will be paid in early 2001 based on the average fair market value of the Company's common stock during the last 12 consecutive trading days in 2000. The SARs will first become exercisable on January 2, 2001, and can be exercised until they expire on December 31, 2007. The 1998 stock unit and SAR grants were determined so that the average current salary and the average grant date present value of the 1998 LTIP grants for the five named executive officers would approximate the 50th percentile of 1997 comparator utility total compensation practice.

Through the combination of base salary, and, during 1996, 1997 and 1998, stock unit and SAR grants, the Committee seeks to focus the efforts of officers toward improving, annually and over the longer-term, the financial returns for the Company's shareholders.

COMPENSATION OF WILLIAM E. DAVIS, CHAIRMAN OF THE BOARD AND CHIEF EXECUTIVE OFFICER

Mr. Davis became Chief Executive Officer on May 1, 1993. In April 1996, Mr. Davis voluntarily reduced his annual salary from a level of $490,000 to the current level of $450,500. The Committee has been advised by its consultant that Mr. Davis' 1997 salary falls well below the 25th percentile relative to the Chief Executive Officers of the Comparator Utilities. On December 13, 1995, the Board granted Mr. Davis 25,000 stock units and 142,500 SARs, with an exercise price of $10.75, under the 1995 Stock Incentive Plan. As set forth above, SIP stock units will be paid to Mr. Davis and the other named executive officers in 1998. Mr. Davis' SIP stock unit and SAR grants were intended to provide competitive total compensation opportunities during the 1996 and 1997 period, depending on the Company's stock price, considering that his salary would not be increased and that he would receive no annual incentive compensation payments and no stock options during this two-year period.

As previously indicated, the Committee and the Board of Directors seek to provide a continuous program of long-term stock incentives beyond 1997 when SIP stock unit grants became payable and SIP SAR grants became exercisable. Accordingly, on September 25, 1996 the Board of Directors approved a grant of 45,000 stock units and 90,000 SARs, with an exercise price of $8.00, for Mr. Davis for the 1996-1998 performance period. On January 29, 1997 the Board of Directors approved a grant of 35,000 stock units and 70,000 SARs, with an exercise price of $10.30, for the 1997-1999 performance period. Both the 1996-1998 and 1997-1999 grants were made under the terms of the LTIP. The size of the 1996-1998 and 1997-1999 LTIP grants for Mr. Davis was determined so that the grant date present value of both grants, in combination with his current salary and his SIP grants, would approximate the 50th percentile for Comparator Utility chief executive officers during the 1995-1997 period. The competitiveness of the compensation Mr. Davis actually realizes from the SIP and LTIP grants is dependent on the market value of the Company's common stock at the end of 1997, 1998, and 1999.

As previously indicated, the Board of Directors approved a January 19, 1998 grant of LTIP stock units and SARs for Mr. Davis for the period 1998-2000. The size of these grants was determined so that the sum of his current salary plus the grant date present value of the 1998 stock unit and SAR grants would fall approximately midway between the 25th and 50th percentiles of 1997 total compensation practice for electric/gas utilities of comparable size.

The Committee is aware of the limitations that tax legislation has placed on the tax deductibility of compensation in excess of $1 million which is paid in any year to an executive officer. Currently none of the executive officers has received compensation subject to such limitations. The Committee will continue to monitor developments in this area and take appropriate actions to preserve the tax deductibility of compensation paid to executive officers, should this become necessary.

Submitted by the Compensation and Succession Committee of the Board of Directors:

Stephen B. Schwartz, Chairperson
William F. Allyn
Edmund M. Davis
Anthony H. Gioia
Henry A. Panasci, Jr.

EXECUTIVE COMPENSATION

The table below sets forth all compensation paid by the Company for services rendered in all capacities during the fiscal years ended December 31, 1997, December 31, 1996 and December 31, 1995, to the Chairman of the Board and Chief Executive Officer and to each of the other four most highly compensated executive officers of the Company for the fiscal year ended December 31, 1997.

SUMMARY COMPENSATION TABLE
Fiscal Years 1997, 1996 and 1995

			Annual Compensation		
Name	Position	Year	Salary ($)(A)	Bonus($)	Other Annual Compensation($)(C)
W. E. Davis	Chairman of the	1997	450,501	0	110
	Board and Chief	1996	462,351	0	0
	Executive Officer	1995	473,542	0	0
A. J. Budney, Jr.					
	President and	1997	315,002	0	110
	Chief Operating	1996	315,002	0	2,956
	Officer	1995	236,251	50,000(B)	32,727
B. R. Sylvia	Executive Vice	1997	295,001	0	110
	President	1996	295,001	0	0
		1995	295,001	0	0
J. W. Powers	Senior Vice	1997	210,190	0	110
	President	1996	211,002	0	0
		1995	209,251	0	0
D. D. Kerr	Senior Vice	1997	210,001	0	110
	President	1996	210,001	0	0
		1995	191,085	0	0

			Long-Term Compensation Awards		
Name	Position	Year	Restricted Stock Awards ($)(D)	Securities Underlying Options/SARs(#)	All Other Compensation($) (E)
W. E. Davis	Chairman of the	1997	371,875	70,000	42,358
	Board and Chief	1996	360,000	90,000	43,365
	Executive Officer	1995	246,875	152,500	35,729
A. J. Budney, Jr.					
	President and	1997	185,938	35,000	16,436
	Chief Operating	1996	180,000	45,000	24,975
	Officer	1995	148,125	76,000	48,541
B. R. Sylvia	Executive Vice	1997	117,938	22,200	11,153
	President	1996	114,000	28,500	10,174
		1995	98,750	49,000	24,832
J. W. Powers	Senior Vice	1997	85,000	16,000	187,878
	President	1996	142,000	30,000	30,541
		1995	0	22,000	58,466
D. D. Kerr	Senior Vice	1997	85,000	16,000	7,953
	President	1996	82,000	20,500	9,415
		1995	74,063	31,500	7,338

(A) Includes all employee contributions to the Employees' Savings Fund Plan.

(B) 1995 bonus for Mr. Budney represents a bonus for 1995 guaranteed at the time he was hired if earnings per share thresholds were not met under the Officer Incentive Compensation Plan (an annual incentive compensation plan adopted by the Board of Directors on December 13, 1990, and suspended for 1996 and 1997 as a condition of participation in the SIP).

(C) 1996 and 1995 Other Annual Compensation for Mr. Budney represents amounts reimbursed for payment of taxes associated with relocation expenses. 1997 Other Annual Compensation for Messrs. Davis, Budney, Sylvia and Powers and Ms. Kerr represents amounts reimbursed for payment of taxes associated with non-cash compensation.

(D) In 1995, 57,500 stock units were granted to the above named executive officers pursuant to the SIP adopted by the Board of Directors on December 14, 1995. These stock units vested and became payable on December 31, 1997. No dividend equivalents were credited on these stock units. The 1995 values listed in the table were calculated by multiplying the stock units granted by the closing market price of the company's stock ($9.875) on the date of the grant (December 31, 1995).

In 1996, 109,750 stock units were granted to the above named executive officers pursuant to the LTIP adopted by the Board of Directors on September 25, 1996. These grants were made for the three-year period January 1, 1996, through December 31, 1998, and vest and become payable on December 31, 1998. The 1996 values listed in the table were calculated by multiplying the stock units granted by $8.00, the price at the time these stock unit grants were determined. Dividend equivalents, if any, will be credited on these grants and will be paid when the related stock units are paid. For Mr. Powers, the value also includes the value of stock units granted in 1996 under the 1995 SIP.

In 1997, 79,600 stock units were granted to the above named executive officers pursuant to the LTIP adopted by the Board of Directors on September 25, 1996. These grants were made for the three-year period January 1, 1997, through December 31, 1999, and vest and become payable on December 31, 1999. The 1997 values listed in the table were calculated by multiplying the stock units granted by $10.625, the price at the time these stock unit grants were determined. Dividend equivalents, if any, will be credited on these grants and will be paid when the related stock units are paid.

As of the end of the 1997 fiscal year, based on a closing market price of $10.50, Mr. Davis held 105,000 stock units having a market value of $1,102,500; Mr. Budney held 55,000 stock units having a market value of $577,500; Mr. Sylvia held 35,350 stock units having a market value of $371,175; Mr. Powers held 25,750 stock units having a market value of $270,375; and Ms. Kerr held 25,750 stock units having a market value of $270,375.

(E) All Other Compensation for 1997 includes: employer contributions to the Company's Employees' Savings Fund Plan: Mr. Davis ($4,800), Mr. Sylvia ($4,800), Mr. Powers ($4,800), and Ms. Kerr ($4,800); taxable portion of life insurance premiums: Mr. Davis ($13,743), Mr. Budney ($2,436), Mr. Sylvia ($3,537), Mr. Powers ($3,528), and Ms. Kerr ($1,653); employer contributions to the Company's Excess Benefit Plan: Mr. Davis ($8,715), Mr. Sylvia ($1,837), Mr. Powers ($560), and Ms. Kerr ($1,500); director fees received from Opinac Energy Corporation: Mr. Davis ($15,000), Mr. Budney ($14,000), and Mr. Powers ($11,000); lump sum payment for accrued, unused vacation upon retirement: Mr. Powers ($62,490); severance allowance paid pursuant to Employment Agreement: Mr. Powers ($105,500); personal travel allowance: Mr. Sylvia ($979).

The following table discloses, for the Chairman of the Board and Chief Executive Officer, Mr. William E. Davis and the other named executive officers, the number and terms of SARs granted during the fiscal year ended December 31, 1997.

Option/SAR Grants in Last Fiscal Year

Individual Grants

Name	Number of Securities Underlying Options/SARs Granted (#)	% of Total Options/SARs Granted to Employees In Fiscal Year	Exercise or Base Price ($/Sh)
W. E. Davis	70,000	23.62%	10.30
A. J. Budney, Jr.	35,000	11.81%	10.30
B. R. Sylvia	22,200	7.49%	10.30
J. W. Powers	16,000	5.40%	10.30
D. D. Kerr	16,000	5.40%	10.30

Name	Expiration Date (A)	Grant Date Present Value($) (B)
W. E. Davis	12/31/2006	249,200
A. J. Budney, Jr.	12/31/2006	124,600
B. R. Sylvia	12/31/2006	79,032
J. W. Powers	12/31/2006	56,960
D. D. Kerr	12/31/2006	56,960

(A) SARs granted in 1997 under the LTIP become exercisable January 2, 2000. All SARs become exercisable upon a change in control.

(B) The grant date present value of SARs is calculated using the Black-Scholes Option Pricing Model with the following assumptions: market price of the stock at the September 29, 1997 grant date ($10.30); exercise price of rights that expire on December 31, 2006 ($10.30); stock volatility (0.2957); dividend yield (2.86%); risk free rate (6.00%); exercise term (10 years); Black-Scholes ratio (0.3454); and Black-Scholes value ($3.56) for rights that expire on December 31, 2006. Stock volatility and dividend yield assumptions are based on 36 months of results for the period ending December 31, 1997.

The following table summarizes exercises of options by the Chairman of the Board and Chief Executive Officer, Mr. William E. Davis, and the other named executive officers, the number of unexercised options held by them and the spread (the difference between the current market price of the stock and the exercise price of the option, to the extent that market price at the end of the year exceeds exercise price) on those unexercised options for fiscal year ended December 31, 1997.

Aggregated Option/SAR Exercises in Last Fiscal Year
and Fiscal Year-End Option Values

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs At Fiscal Year End (#) Exercisable	Unexercisable
W. E. Davis	0	0	32,625	312,500
A. J. Budney, Jr.	0	0	0	156,000
B. R. Sylvia	0	0	13,000	99,700
J. W. Powers	0	0	9,000	68,000
D. D. Kerr	0	0	6,000	68,000

Name	Value of Unexercised Options/SARs At Fiscal Year-End ($) (A) Exercisable	Unexercisable
W. E. Davis	0	239,000
A. J. Budney, Jr.	0	119,500
B. R. Sylvia	0	75,690
J. W. Powers	0	78,200
D. D. Kerr	0	54,450

(A) Calculated based on the closing market price of the Company's common stock on December 31, 1997 ($10.50).

NIAGARA MOHAWK POWER CORPORATION
Comparison of Five-Year Cumulative Total Return(1)
vs. S&P 500, EEI and Peer Group of Eastern Region Utilities

[ILLUSTRATION OF PERFORMANCE GRAPH--ATTACHED]

	1992	1993	1994	1995	1996	1997
NMPC	100.00	110.46	83.26	60.67	63.07	67.07
S&P 500 Index	100.00	110.08	111.53	153.45	188.68	251.63
EEI Index	100.00	111.66	97.28	123.91	123.13	159.17
Peer Group	100.00	109.15	93.87	124.16	122.02	158.83

Assumes $100 invested on December 31, 1992 in Niagara Mohawk's stock, S&P 500, EEI and Eastern Region utilities. All dividends assumed to be reinvested over the five-year period.

In prior years, the Company has compared its five-year total shareholder returns to a peer group comprised of the 23 eastern region utilities listed listed below. In future years, the Company intends to compare its total shareholder returns to the Edison Electric Institute Combination Gas and Electric Investor-Owned Utilities Index ("EEI Index"), which is a published industry index. In view of the nationwide deregulation of the electric and gas utility industry, the Company believes that a national peer group, such as the EEI Index, is more appropriate than the regional utility peer group used in prior years. Furthermore, the EEI Index is more appropriate since it is composed entirely of combination electric and gas utilities, like Niagara Mohawk.

PEER GROUP OF EASTERN REGION UTILITIES:

Allegheny Energy Inc.
Atlantic Energy, Inc.
Baltimore Gas & Electric Company
Boston Edison Company
Central Hudson Gas & Electric Corp.
Central Maine Power Co.
Consolidated Edison Co. of New York, Inc.
DQE, Inc.
Delmarva Power & Light Co.
Eastern Utilities Associates
General Public Utilities Corp.
Keyspan Energy Corp.
Long Island Lighting Co.
National Fuel Gas Company
New England Electric System
New York State Electric & Gas Corp.
Northeast Utilities
Orange & Rockland Utilities Inc.
PECO Energy Company
PP&L Resources Inc
Public Service Enterprise Group Inc.
Rochester Gas & Electric Corp.
The United Illuminating Company

(1) Total returns for each Eastern Region Utility were determined in accordance with the Securities and Exchange Commission's regulations, i.e., weighted according to each issuer's stock market capitalization.

RETIREMENT BENEFITS

The following table illustrates the maximum aggregate pension benefit, with certain deductions for Social Security, payable by the Company under both the Niagara Mohawk Pension Plan ("Basic Plan") and the Company's Supplemental Executive Retirement Plan ("SERP") to an officer in specified average salary and years-of-service classifications. Such benefit amounts have been calculated as though each officer selected a straight life annuity and retired on December 31, 1997 at age 65. The amount of compensation taken into account under a tax-qualified plan is subject to certain annual limits (adjusted for increases in the cost of living, $150,000 in 1996 and $160,000 in 1997). This limitation may reduce benefits payable to highly compensated individuals.

ANNUAL RETIREMENT ALLOWANCE

3-Year Average Annual Salary	10 Years Service*	20 Years Service	30 Years Service	40 Years Service
$150,000	$21,090	$ 81,948	$ 81,948	$ 81,948
225,000	23,555	126,948	126,948	126,948
300,000	23,869	171,948	171,948	171,948
375,000	23,869	216,948	216,948	216,948
450,000	23,869	261,948	261,948	261,948
525,000	23,869	306,948	306,948	306,948

*Subject to five-year average annual salary.

The credited years of service under the Basic Plan and the SERP for the individuals listed in the Summary Compensation Table are Mr. Davis, 8 years; Mr. Budney, 3 years; Mr. Sylvia, 7 years; Mr. Powers, 34 years; Ms. Kerr, 24 years.

The Basic Plan, a noncontributory, tax-qualified defined benefit plan, provides all employees of the Company with a minimum retirement benefit related to the highest consecutive five-year average compensation.

Compensation covered by the Basic Plan includes only the participant's base salary or pay, subject to the maximum annual limit noted above. Directors who are not employees are not eligible to participate.

The SERP is a nonqualified, noncontributory defined benefit plan providing additional benefits to certain officers of the Company upon retirement after age 55 who have 20 or more years of employment. The Committee may grant exceptions to these requirements. The SERP provides for payment monthly of an amount equal to the greater of (i) 60% of monthly base salary averaged over the final 36 months of employment, less benefits payable under the Basic Plan, retirement benefits accrued during previous employment and one-half of the maximum Social Security benefit to which the participant may be entitled at the time of retirement, or (ii) benefits payable under the Basic Plan without regard to the annual benefit limitations imposed by the Internal Revenue Code. Participants in the SERP may elect to receive their benefit in a lump sum payment provided certain established criteria are met.

EMPLOYEE AGREEMENTS

The Company entered into employment agreements with Messrs. Davis, Budney, Sylvia and Powers and Ms. Kerr, effective as of December 20, 1996, which superseded their prior agreements with the Company. The agreements have a three-year term, and, unless either party gives 60 days prior notice to the contrary, the agreements are extended at the end of each year for an additional year. In the event of a change in control (as defined in the agreement), the agreement will remain in effect for a period of at least 36 months thereafter unless a notice not to extend the term of the agreement was given at least 18 months prior to the change in control. The agreements provide that the executive will receive a base salary at the executive's current annual salary or such greater amount determined by the Company and that the executive will be able to participate in the Company's incentive compensation plans according to their terms. In addition, the executive is entitled to business expense reimbursement, vacation, sick leave, perquisites, fringe benefits, insurance coverage and other terms and conditions of the agreement as are provided to employees of the Company with comparable rank and seniority. Under an amendment to the agreements effective as of June 9, 1997, if an executive has completed eight years of service and attained age 55 at the time of the executive's termination of employment, the executive (and eligible dependents) will be entitled to coverage for medical, prescription drug, dental and hospitalization benefits equal to those provided by the Company on March 26, 1997 for the remainder of the executive's life with all premiums therefore paid by the Company. If an executive has completed eight years of service but has not attained age 55 upon terminating employment, such benefits will be provided when the executive attains age 55.

The employment agreements also provide that the executive's benefits under the SERP will be based on the executive's salary, annual incentive awards and SIP awards, as applicable. Further, if the executive's employment is terminated by the Company without cause (whether prior to or after a change in control), or by the executive for good reason after a change in control, or after completing eight years of service, the agreements provide that the executive will be deemed fully vested under such plan without reduction for early commencement. If the executive is under age 55 at the time of such termination, the executive will be entitled to a fully vested benefit under the SERP upon attaining age 55, without reduction for early commencement.

The agreements restrict under certain circumstances prior to a change in control the executive's ability to compete with the Company and to use confidential information concerning the Company. In the event of a dispute over an executive's rights under the executive's agreement following a change in control of the Company, the Company will pay the executive's reasonable legal fees with respect to the dispute unless the executive's claims are found to be frivolous.

If the executive's employment is terminated by the Company without cause prior to a change in control (as defined in the agreement), the executive will be entitled to a lump sum severance benefit in an amount equal to two times the executive's base salary plus an amount equal to two times the greater of the executive's (i) most recent annual incentive award or (ii) average annual incentive award paid over the previous three years (a portion of the value of the SIP awards to the executive will be treated as incentive awards for 1996 and 1997 for this purpose). In addition, the executive will receive a pro rata portion of the incentive award which would have been payable to the executive for the fiscal year in which termination of employment occurs provided that the executive has been employed for 180 days in such fiscal year. In the event of such termination of employment, the executive will also be entitled to continued participation in the Company's employee benefit plans for two years, coverage for the balance of the executive's life under a life insurance policy providing a death benefit equal to 2.5 times the executive's base salary at termination and payment by the Company of fees and expenses or any executive recruiting or placement firm in seeking new employment.

If, following a change in control, the executive's employment is terminated by the Company without cause or by the executive for good reason (as defined in the agreement), the executive will be entitled to a lump sum severance benefit equal to four times the executive's base salary. The executive will also be entitled to the additional benefits referred to in the last sentence of the preceding paragraph, except that employee benefit plan coverage for medical, prescription drug, dental and hospitalization benefits will continue for the remainder of the executive's life with all premiums therefor paid by the Company and coverage under other employee benefit plans will continue for four years. In the event that the payments to the executive upon termination of employment following a change in control would subject the executive to the excise tax on excess parachute payments under the Internal Revenue Code, the Company will reimburse the executive for such excise tax (and the income tax and excise tax on such reimbursement).

In November 1994, the Company entered into a supplemental agreement with Mr. Powers in exchange for his foregoing retirement under the Company's Voluntary Employee Reduction Program and continuing employment with the Company until December 31, 1996. This agreement was modified by an agreement between Mr. Powers and the Company entered into in October 1996 in exchange for his foregoing retirement on December 31, 1996, and continuing employment with the Company for up to 12 additional months. Mr. Powers retired from the Company effective December 31, 1997. Under the agreements, Mr. Powers became entitled to a lump sum payment following the successful closing of the sale of HYDRA-CO Enterprises, Inc., and to a severance allowance equal to one-half of his annual salary in effect on December 31, 1996, which was paid to him in January 1997. The agreements also provide that Mr. Powers would be entitled to (i) a SIP award of 7,500 stock units and 9,500 SARs, which would be fully vested (assuming retirement during 1997) and payable (in the case of stock units) or exercisable (in the case of SARs) on December 31, 1997, (ii) long-term incentive grants equivalent to those provided to other senior vice presidents for the 1996-1998 and 1997-1999 cycles (prorated for his period of service during those cycles), (iii) a lump sum payment for unused vacation for 1995, 1996 and 1997 upon retirement and (iv) "grandfathered" retiree medical coverages in effect on December 31, 1996. Under the agreements Mr. Powers also is entitled to a benefit under the Company's SERP no less than his benefit calculated as of November 1994, and to have the fees he received as a member of the board of directors of Opinac Energy Corporation (or would have received in the event that such fees are eliminated) taken into account in calculating his benefit under this plan period. In January 1997, the Committee agreed that if Mr. Powers elected to receive a lump sum payment of his benefit under the SERP (which he did), it would be based on a discount rate no higher than the applicable discount rate in effect under the plan on December 31, 1996.

COMPENSATION OF DIRECTORS

Directors who are not employees of the Company receive an annual retainer of $20,000 and $1,000 per Board meeting attended. Directors who are not employees and who chair any of the standing Board Committees receive an additional annual fee of $3,000 and those who serve on any of the standing Board Committees, including the chair, receive $850 per Committee meeting attended.

The Company also reimburses its directors for travel, lodging and related expenses they incur in attending Board and Committee meetings.

The Board of Directors terminated the Outside Director Retirement Plan effective December 31, 1995. The plan paid annual retirement benefits equal to the annual retainer in effect at the time of retirement to outside directors who retired on or after age 65 with 10 years of service. Directors under age 60 had the present value of their accrued benefits as of December 31, 1995 converted into deferred stock units of equivalent value which become payable upon the director's termination from the Board. Directors age 60 or older were given an election to (1) continue to receive grandfathered retirement benefits based on the annual retainer in 1995, (2) convert the present value of their accrued benefits into deferred stock units, or (3) receive half the grandfathered retirement benefit and convert half the present value of their accrued benefit into deferred stock units. Four directors elected to continue to receive the grandfathered Retirement Plan benefits.

Deferred Stock Units ("DSUs"), administered in accordance with the terms of the Outside Director Deferred Stock Unit Plan adopted by the Board of Directors on December 2, 1996, are paid when a person ceases to be an outside director, either in a lump sum or in five equal annual installments. The first DSU installment payment would be made shortly after the director's service ends and the other installments would be paid on the first through fourth anniversaries of such date, based on the prevailing stock price at that time.

DSUs are credited with respect to any dividends paid during the term of their deferral. Such dividend credits are reinvested into DSUs of equivalent current value based on the prevailing price of the Company's common stock at that time.

Commencing in 1996, and annually thereafter, each outside director is credited with DSUs equal in value to 50% of the prevailing year's annual retainer (60% for Committee Chairs). Accordingly, all outside directors were credited with 1,168 DSUs (1,402 for Committee Chairs) based on a closing stock price of $8.5625 on May 7, 1997. The beneficial stock ownership table in Item 12, shows the DSUs which have been credited to each of the outside directors under this plan as of March 10, 1998.

The Company provides certain health and life insurance benefits to directors who are not employees of the Company. Each outside director covered under the

Company's health care plans contributes approximately 20 percent of the monthly costs associated with these plans. During 1997, the following directors received the indicated benefits under the foregoing arrangements: Mr. Burkhardt ($3,689), Mr. Costle ($3,178), Mr. Edmund Davis ($6,602), Mr. Donlon ($204), Mr. Gioia ($4,077), Dr. Hill ($3,306), Mr. Panasci ($212), Dr. Peterson ($2,361), Mr. Riefler ($4,856) and Mr. Schwartz ($384). Mr. Burkhardt received a consulting fee of $18,000 during 1997.

COMPENSATION AND SUCCESSION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

Directors Allyn, Edmund Davis, Gioia, Panasci and Schwartz, all of whom are non-employee directors, are the members of the Compensation and Succession Committee.

No person serving during 1997 as a member of the Compensation and Succession Committee of the Board served as an officer or employee of the Company or any of its subsidiaries during or prior to 1997.

No person serving during 1997 as an executive officer of the Corporation serves or has served as a director or a member of the compensation committee of any other entity that has an executive officer who serves or has served either as a member of the Compensation and Succession Committee or as a member of the Board of Directors of Niagara Mohawk Power Corporation.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table shows the persons (as the term is used in Section 13(d)(3) of the Securities Exchange Act of 1934) known to the Company to own more than five percent (5%) of the Company's common stock as of December 31, 1997.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent Of Class
Common Stock	FMR Corp. 82 Devonshire Street Boston, Massachusetts 02109	14,441,831(1)	10.00%
Common Stock	Fidelity Management Trust Co. 82 Devonshire Street Boston, Massachusetts 02109	11,829,786(2)	8.19%
Common Stock	The Prudential Insurance Company of America 751 Broad Street Newark, New Jersey 07102-3777	8,404,245(3)	5.82%

(1) Includes 1,873,631 shares with respect to which FMR Corp. has sole voting power and 14,441,831 with sole power to dispose or to direct disposition as reported on Schedule 13G, dated February 14, 1998, filed with the SEC.

(2) The above represents shares in the Company's Non-Represented and Represented Employees' Savings Fund Plans. Fidelity Management Trust Company serves as Trustee. The Trustee will vote all shares of common stock held in the Trusts established for the Plans in accordance with the directions received from the employees participating in the Plans. The Trustee will vote shares for which it receives no instructions in the same proportion as it votes shares for which it receives instructions.

(3) Includes 789,900 shares with respect to which Prudential Insurance Company of America has sole voting power; 7,575,445 shares with shared power to vote; 789,900 shares with sole power to dispose or to direct disposition; and 7,614,345 shares with shared power to dispose, as reported on Schedule 13G, dated February 10, 1998, filed with the SEC.

The Company believes that holders of approximately 88.2% of the Company's common stock outstanding as of December 31, 1997, elected to hold their shares, not in their own names, but in the names of banking or financial intermediaries. Accordingly, as of that date, 127,431,405 shares were registered in the nominee name of The Depository Trust Company, Cede & Co.

SECURITY OWNERSHIP OF DIRECTORS AND EXECUTIVE OFFICERS

The following table reflects shares of the Company's common stock beneficially owned (or deemed to be beneficially owned pursuant to the rules of the Securities and Exchange Commission) as of March 10, 1998, by each director of the Company, each of the named executive officers in the Summary Compensation Table below and the current directors and executive officers of the Company as a group. The table also lists the number of stock units credited to directors, named executive officers and the directors and executive officers of the Company as a group as of March 10, 1998, pursuant to the Company's compensation and benefit programs. No voting rights are associated with stock units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership*	Percent Of Class
Common Stock	Directors:		
	William F. Allyn	1,000	**
	Albert J. Budney, Jr.	10,500(1)	**
	Lawrence Burkhardt, III	452	**
	Douglas M. Costle	500	**
	Edmund M. Davis	2,274	**
	William E. Davis	45,238(2)	**
	William J. Donlon	15,343(3)	**
	Anthony H. Gioia	500	**
	Bonnie Guiton Hill	1,000	**
	Henry A. Panasci, Jr.	2,500	**
	Patti McGill Peterson	500	**
	Donald B. Riefler	1,000	**
	Stephen B. Schwartz	500	**
	Named Executives:		
	B. Ralph Sylvia	22,787(4)	**
	John W. Powers	26,659(5)	**
	Darlene D. Kerr	15,726(6)	**
	All Directors and Executive Officers (23) as a group	197,260(7)	**

Title of Class	Name and Address of Beneficial Owner	Number of Stock Units Held
Common Stock	Directors:	
	William F. Allyn	9,158(8)
	Albert J. Budney, Jr.	72,500(9)
	Lawrence Burkhardt, III	2,773(8)
	Douglas M. Costle	9,551(8)
	Edmund M. Davis	26,386(8)
	William E. Davis	140,000(9)
	William J. Donlon	0
	Anthony H. Gioia	2,311(8)
	Bonnie Guiton Hill	8,077(8)
	Henry A. Panasci, Jr.	2,311(8)
	Patti McGill Peterson	11,199(8)
	Donald B. Riefler	25,877(8)
	Stephen B. Schwartz	11,204(8)
	Named Executives:	
	B. Ralph Sylvia	46,450(9)
	John W. Powers	25,750(9)
	Darlene D. Kerr	36,850(9)
	All Directors and Executive Officers (23) as a group	569,297

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* Based on information furnished to the Company by the Directors and Executive Officers. Includes shares of common stock credited under the Employees' Savings Fund Plan as of March 10, 1998.

** Less than one percent.

(1) Includes options for 10,000 shares of common stock exercisable within 60 days.
(2) Includes presently exercisable options for 42,625 shares of common stock.
(3) Includes presently exercisable options for 13,333 shares of common stock.
(4) Includes presently exercisable options for 18,000 shares of common stock.
(5) Includes presently exercisable options for 12,000 shares of common stock.
(6) Includes presently exercisable options for 9,000 shares of common stock.
(7) Includes presently exercisable options for 141,083 shares of common stock.
(8) Represents deferred stock units granted pursuant to the Outside Director Deferred Stock Unit Plan. No voting rights are associated with deferred stock units. For additional information regarding deferred stock units, refer to Item 11. Executive Compensation - "Compensation of Directors".

(9) Represents stock units granted in 1995 pursuant to the SIP and in 1996, 1997 and 1998 pursuant to the LTIP. No voting rights are associated with stock units. For additional information regarding stock units granted to named executives, refer to Item 11. Executive Compensation - "Long-Term Incentive Plan").

In addition to the shares of the Company's common stock, Albert J. Budney, Jr. indirectly owns 100 shares of the Company's Preferred Stock, 9½% Series.

Item 13. Certain Relationships and Related Transactions.

The Company has nothing to report for this item.

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(a) Certain documents filed as part of the Form 10-K.

(1) INDEX OF FINANCIAL STATEMENTS

Report of Independent Accountants

Consolidated Statements of Income and Retained Earnings for each of the three years in the period ended December 31, 1997
Consolidated Balance Sheets at December 31, 1997 and 1996
Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 1997

Notes to Consolidated Financial Statements

Separate financial statements of the Company have been omitted since it is primarily an operating company and all consolidated subsidiaries are wholly-owned directly or by subsidiaries.

(2) The following financial statement schedules of the Company for the years ended December 31, 1997, 1996 and 1995 are included:

Report of Independent Accountants on Financial Statement Schedule

Consolidated Financial Statement Schedule:

II--Valuation and Qualifying Accounts and Reserves

The Financial Statement Schedule above should be read in conjunction with the Consolidated Financial Statements in Part II, Item 8 (Financial Statements and Supplementary Data).

Schedules other than those mentioned above are omitted because the conditions requiring their filing do not exist or because the required information is given in the financial statements, including the notes thereto.

(3) List of Exhibits:

See Exhibit Index.

(b) Reports on Form 8-K:

Form 8-K Reporting Date - October 10, 1997
Item reported - Item 5. Other Events.
Registrant filed information concerning the PowerChoice settlement.

Form 8-K Reporting Date - February 11, 1998
Item reported - Item 5. Other Events.
Registrant filed information concerning the January 1998 ice storm.

(c) Exhibits.

See Exhibit Index.

(d) Financial Statement Schedule.

See (a)(2) above.

REPORT OF INDEPENDENT ACCOUNTANTS ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors of
Niagara Mohawk Power Corporation

Our audits of the consolidated financial statements of Niagara Mohawk Power Corporation referred to in our report dated March 26, 1998 appearing in this Form 10-K also included an audit of the Financial Statement Schedule listed in Item 14(a) of this Form 10-K. In our opinion, this Financial Statement Schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

Price Waterhouse LLP

PRICE WATERHOUSE LLP

Syracuse, New York
March 26, 1998

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

(In Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (a)	Balance at End of Period
Allowance for Doubtful Accounts - deducted from Accounts Receivable in the Consolidated Balance Sheets					
1997	$52,096	$ 46,549	$ 3,000 (b)	$39,097	$62,548
1996	20,000	127,648	800 (b)	96,352	52,096
1995	3,600	31,284	16,400 (b)	31,284	20,000

(a) Uncollectible accounts written off net of recoveries of $14,416, $12,842, and $10,830 in 1997, 1996 and 1995, respectively.

(b) The Company increased its allowance for doubtful accounts in 1995 and recorded a regulatory asset of $16,400, which reflects the amount that the Company expects to recover in rates. In 1996, regulatory asset increased by $800 to $17,200 and in 1997, regulatory asset increased $3,000 to $20,200.

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

(In Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period (c)
Miscellaneous Valuation Reserves					
1997	$ 37,740	$ 2,207	$ -	$ 4,049	$35,898
1996	39,426	10,261	-	11,947	37,740
1995	29,197	18,719	-	8,490	39,426

(c) The reserves relate primarily to certain inventory and non-rate base properties.

NIAGARA MOHAWK POWER CORPORATION
Exhibit Index

In the following exhibit list, NMPC refers to the Company and CNYP refers to Central New York Power Corporation, a predecessor company. Each document referred to below is incorporated by reference to the files of the Commission, unless the reference to the document in the list is preceded by an asterisk. Previous filings with the Commission are indicated as follows:

A--NMPC Registration Statement No. 2-8214;
C--NMPC Registration Statement No. 2-8634;
F--CNYP Registration Statement No. 2-3414;
G--CNYP Registration Statement No. 2-5490;
V--NMPC Registration Statement No. 2-10501;
X--NMPC Registration Statement No. 2-12443;
Z--NMPC Registration Statement No. 2-13285;
CC--NMPC Registration Statement No. 2-16193;
DD--NMPC Registration Statement No. 2-18995;
GG--NMPC Registration Statement No. 2-25526;
HH--NMPC Registration Statement No. 2-26918;
II--NMPC Registration Statement No. 2-29575;
JJ--NMPC Registration Statement No. 2-35112;
KK--NMPC Registration Statement No. 2-38083;
OO--NMPC Registration Statement No. 2-49570;
QQ--NMPC Registration Statement No. 2-51934;
SS--NMPC Registration Statement No. 2-52852;
TT--NMPC Registration Statement No. 2-54017;
VV--NMPC Registration Statement No. 2-59500;
CCC--NMPC Registration Statement No. 2-70860;
III--NMPC Registration Statement No. 2-90568;
OOO--NMPC Registration Statement No. 33-32475;
PPP--NMPC Registration Statement No. 33-38093;
QQQ--NMPC Registration Statement No. 33-47241;
RRR--NMPC Registration Statement No. 33-59594;

b--NMPC Annual Report on Form 10-K for year ended December 31, 1990; and
c--NMPC Annual Report on Form 10-K for year ended December 31, 1992; and
d--NMPC Annual Report on Form 10-K for year ended December 31, 1993; and
e--NMPC Annual Report on Form 10-K for year ended December 31, 1994; and
f--NMPC Annual Report on Form 10-K for year ended December 31, 1995; and
g--NMPC Annual Report on Form 10-K for year ended December 31, 1996.
h--NMPC Quarterly Report on Form 10-Q for quarter ended March 31, 1993; and
i--NMPC Quarterly Report on Form 10-Q for quarter ended September 30, 1993;
j--NMPC Quarterly Report on Form 10-Q for quarter ended June 30, 1995; and
k--NMPC Quarterly Report on Form 10-Q for quarter ended September 30, 1996;
l--NMPC Quarterly Report on Form 10-Q for quarter ended June 30, 1997; and
m--NMPC Quarterly Report on Form 10-Q for quarter ended September 30, 1997.
n--NMPC Report on Form 8-K dated July 9, 1997; and
o--NMPC Report on Form 8-K dated October 10, 1997.

In accordance with Paragraph 4(iii) of Item 601 (b) of Regulation S-K, the Company agrees to furnish to the Securities and Exchange Commission, upon request, a copy of the agreements comprising the $804 million senior debt facility that the Company completed with a bank group during March 1996. The total amount of long-term debt authorized under such agreement does not exceed 10 percent of the total consolidated assets of the Company and its subsidiaries.

Exhibit No.	Description of Instrument	Incorporation by Reference: Previous Filing	Incorporation by Reference: Previous Exhibit Designation
3(a)(1)	--Certificate of Consolidation of New York Power and Light Corporation, Buffalo Niagara Electric Corporation and Central New York Power Corporation, filed in the office of the New York Secretary of State, January 5, 1950.	e	3(a)(1)
3(a)(2)	--Certificate of Amendment of Certificate of Incorporation of NMPC, filed in the office of the New York Secretary of State, January 5, 1950.	e	3(a)(2)
3(a)(3)	--Certificate of Amendment of Certificate of Incorporation of NMPC, pursuant to Section 36 of the Stock Corporation Law of New York, filed August 22, 1952, in the office of the New York Secretary of State.	e	3(a)(3)
3(a)(4)	--Certificate of NMPC pursuant to Section 11 of the Stock Corporation Law of New York filed May 5, 1954 in the office of the New York Secretary of State.	e	3(a)(4)
3(a)(5)	--Certificate of Amendment of Certificate of Incorporation of NMPC, pursuant to Section 36 of the Stock Corporation Law of New York, filed January 9, 1957 in the office of the New York Secretary of State.	e	3(a)(5)
3(a)(6)	--Certificate of NMPC pursuant to Section 11 of the Stock Corporation Law of New York, filed May 22, 1957 in the office of the New York Secretary of State.	e	3(a)(6)
3(a)(7)	--Certificate of NMPC pursuant to Section 11 of the Stock Corporation Law of New York, filed February 18, 1958 in the office of the New York Secretary of State.	e	3(a)(7)
3(a)(8)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 5, 1965 in the office of the New York Secretary of State.	e	3(a)(8)
3(a)(9)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 24, 1967 in the office of the New York Secretary of State.	e	3(a)(9)
3(a)(10)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 19, 1968 in the office of the New York Secretary of State.	e	3(a)(10)
3(a)(11)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed September 22, 1969 in the office of the New York Secretary of State.	e	3(a)(11)
3(a)(12)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 12, 1971 in the office of the New York Secretary of State.	e	3(a)(12)

Exhibit No.	Description of Instrument	Incorporation by Reference: Previous Filing	Previous Exhibit Designation
3(a)(13)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 18, 1972 in the office of the New York Secretary of State.	e	3(a)(13)
3(a)(14)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed June 26, 1973 in the office of the New York Secretary of State.	e	3(a)(14)
3(a)(15)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 9, 1974 in the office of the New York Secretary of State.	e	3(a)(15)
3(a)(16)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed March 12, 1975 in the office of the New York Secretary of State.	e	3(a)(16)
3(a)(17)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 7, 1975 in the office of the New York Secretary of State.	e	3(a)(17)
3(a)(18)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 27, 1975 in the office of the New York Secretary of State.	e	3(a)(18)
3(a)(19)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 7, 1976 in the office of the New York Secretary of State.	e	3(a)(19)
3(a)(20)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed September 28, 1976 in the office of the New York Secretary of State.	e	3(a)(20)
3(a)(21)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed January 27, 1978 in the office of the New York Secretary of State.	e	3(a)(21)
3(a)(22)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 8, 1978 in the office of the New York Secretary of State.	e	3(a)(22)
3(a)(23)	--Certificate of Correction of the Certificate of Amendment filed May 7, 1976 of the Certificate of Incorporation under Section 105 of the Business Corporation Law of New York filed July 13, 1978 in the office of the New York Secretary of State.	e	3(a)(23)
3(a)(24)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed July 17, 1978 in the office of the New York Secretary of State.	e	3(a)(24)

Exhibit No.	Description of Instrument	Incorporation by Reference: Previous Filing	Incorporation by Reference: Previous Exhibit Designation
3(a)(25)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed March 3, 1980 in the office of the New York Secretary of State.	e	3(a)(25)
3(a)(26)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed March 31, 1981 in the office of the New York Secretary of State.	e	3(a)(26)
3(a)(27)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed March 31, 1981 in the office of the New York Secretary of State.	e	3(a)(27)
3(a)(28)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed April 22, 1981 in the office of the New York Secretary of State.	e	3(a)(28)
3(a)(29)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 8, 1981 in the office of the New York Secretary of State.	e	3(a)(29)
3(a)(30)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed April 26, 1982 in the office of the New York Secretary of State.	e	3(a)(30)
3(a)(31)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed January 24, 1983 in the office of the New York Secretary of State.	e	3(a)(31)
3(a)(32)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed August 3, 1983 in the office of the New York Secretary of State.	e	3(a)(32)
3(a)(33)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed December 27, 1983 in the office of the New York Secretary of State.	e	3(a)(33)
3(a)(34)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed December 27, 1983 in the office of the New York Secretary of State.	e	3(a)(34)
3(a)(35)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed June 4, 1984 in the office of the New York Secretary of State.	e	3(a)(35)
3(a)(36)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed August 29, 1984 in the office of the New York Secretary of State.	e	3(a)(36)

		Incorporation by Reference	
Exhibit No.	Description of Instrument	Previous Filing	Previous Exhibit Designation
3(a)(37)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed April 17, 1985, in the office of the New York Secretary of State.	e	3(a)(37)
3(a)(38)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 3, 1985, in the office of the New York Secretary of State.	e	3(a)(38)
3(a)(39)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed December 24, 1986 in the office of the New York Secretary of State.	e	3(a)(39)
3(a)(40)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed June 1, 1987 in the office of the New York Secretary of State.	e	3(a)(40)
3(a)(41)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed July 16, 1987 in the office of the New York Secretary of State.	e	3(a)(41)
3(a)(42)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 27, 1988 in the office of the New York Secretary of State.	e	3(a)(42)
3(a)(43)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed September 27, 1990 in the office of the New York Secretary of State.	e	3(a)(43)
3(a)(44)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed October 18, 1991 in the office of the New York Secretary of State.	e	3(a)(44)
3(a)(45)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 5, 1994 in the office of the New York Secretary of State.	e	3(a)(45)
3(a)(46)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed August 5, 1994 in the office of the New York Secretary of State.	e	3(a)(46)
*3(b)	--By-Laws of NMPC, as amended February 26, 1998.		
4(a)	--Agreement to furnish certain debt instruments.	e	4(b)
4(b)(1)	--Mortgage Trust Indenture dated as of October 1, 1937 between NMPC (formerly CNYP) and Marine Midland Bank, N.A. (formerly named The Marine Midland Trust Company of New York), as Trustee.	F	**

** Filed October 15, 1937 after effective date of Registration Statement No. 2-3414.

Exhibit No.	Description of Instrument	Incorporation by Reference: Previous Filing	Incorporation by Reference: Previous Exhibit Designation
4(b)(2)	--Supplemental Indenture dated as of December 1, 1938, supplemental to Exhibit 4(1).	VV	2-3
4(b)(3)	--Supplemental Indenture dated as of April 15, 1939, supplemental to Exhibit 4(1).	VV	2-4
4(b)(4)	--Supplemental Indenture dated as of July 1, 1940, supplemental to Exhibit 4(1).	VV	2-5
4(b)(5)	--Supplemental Indenture dated as of October 1, 1944, supplemental to Exhibit 4(1).	G	7-6
4(b)(6)	--Supplemental Indenture dated as of June 1, 1945, supplemental to Exhibit 4(1).	VV	2-8
4(b)(7)	--Supplemental Indenture dated as of August 17, 1948, supplemental to Exhibit 4(1).	VV	2-9
4(b)(8)	--Supplemental Indenture dated as of December 31, 1949, supplemental to Exhibit 4(1).	A	7-9
4(b)(9)	--Supplemental Indenture dated as of January 1, 1950, supplemental to Exhibit 4(1).	A	7-10
4(b)(10)	--Supplemental Indenture dated as of October 1, 1950, supplemental to Exhibit 4(1).	C	7-11
4(b)(11)	--Supplemental Indenture dated as of October 19, 1950, supplemental to Exhibit 4(1).	C	7-12
4(b)(12)	--Supplemental Indenture dated as of February 20, 1953, supplemental to Exhibit 4(1).	V	4-16
4(b)(13)	--Supplemental Indenture dated as of April 25, 1956, supplemental to Exhibit 4(1).	X	4-19
4(b)(14)	--Supplemental Indenture dated as of March 15, 1960, supplemental to Exhibit 4(1).	CC	2-23
4(b)(15)	--Supplemental Indenture dated as of October 1, 1966, supplemental to Exhibit 4(1).	GG	2-27
4(b)(16)	--Supplemental Indenture dated as of July 15, 1967, supplemental to Exhibit 4(1).	HH	4-29
4(b)(17)	--Supplemental Indenture dated as of August 1, 1967, supplemental to Exhibit 4(1).	HH	4-30
4(b)(18)	--Supplemental Indenture dated as of August 1, 1968, supplemental to Exhibit 4(1).	II	2-30
4(b)(19)	--Supplemental Indenture dated as of March 15, 1977, supplemental to Exhibit 4(1).	VV	2-39
4(b)(20)	--Supplemental Indenture dated as of August 1, 1977, supplemental to Exhibit 4(1).	CCC	4(b)(40)

Exhibit No.	Description of Instrument	Incorporation by Reference: Previous Filing	Incorporation by Reference: Previous Exhibit Designation
4(b)(21)	--Supplemental Indenture dated as of March 1, 1978, supplemental to Exhibit 4(1).	CCC	4(b)(42)
4(b)(22)	--Supplemental Indenture dated as of June 15, 1980, supplemental to Exhibit 4(1).	CCC	4(b)(46)
4(b)(23)	--Supplemental Indenture dated as of November 1, 1985, supplemental to Exhibit 4(1).	III	4(b)(64)
4(b)(24)	--Supplemental Indenture dated as of October 1, 1989, supplemental to Exhibit 4(1).	OOO	4(b)(73)
4(b)(25)	--Supplemental Indenture dated as of June 1, 1990, supplemental to Exhibit 4(1).	PPP	4(b)(74)
4(b)(26)	--Supplemental Indenture dated as of November 1, 1990, supplemental to Exhibit 4(1).	PPP	4(b)(75)
4(b)(27)	--Supplemental Indenture dated as of March 1, 1991, supplemental to Exhibit 4(1).	QQQ	4(b)(76)
4(b)(28)	--Supplemental Indenture dated as of October 1, 1991, supplemental to Exhibit 4(1).	QQQ	4(b)(77)
4(b)(29)	--Supplemental Indenture dated as of April 1, 1992, supplemental to Exhibit 4(1).	QQQ	4(b)(78)
4(b)(30)	--Supplemental Indenture dated as of June 1, 1992, supplemental to Exhibit 4(1).	RRR	4(b)(79)
4(b)(31)	--Supplemental Indenture dated as of July 1, 1992, supplemental to Exhibit 4(1).	RRR	4(b)(80)
4(b)(32)	--Supplemental Indenture dated as of August 1, 1992, supplemental to Exhibit 4(1).	RRR	4(b)(81)
4(b)(33)	--Supplemental Indenture dated as of April 1, 1993, supplemental to Exhibit 4(1).	h	4(b)(82)
4(b)(34)	--Supplemental Indenture dated as of July 1, 1993, supplemental to Exhibit 4(1).	i	4(b)(83)
4(b)(35)	--Supplemental Indenture dated as of September 1, 1993, supplemental to Exhibit 4(1).	i	4(b)(84)
4(b)(36)	--Supplemental Indenture dated as of March 1, 1994, supplemental to Exhibit 4(1).	d	4(b)(85)
4(b)(37)	--Supplemental Indenture dated as of July 1, 1994, supplemental to Exhibit 4(1).	e	4(86)
4(b)(38)	--Supplemental Indenture dated as of May 1, 1995, supplemental to Exhibit 4(1).	j	4(87)
4(b)(39)	--Agreement dated as of August 16, 1940, between CNYP, The Chase National Bank of the City of New York, as Successor Trustee, and The Marine Midland Trust Company of New York, as Trustee.	G	7-23

Exhibit No.	Description of Instrument	Incorporation by Reference: Previous Filing	Incorporation by Reference: Previous Exhibit Designation
10-1	--Agreement dated March 1, 1957 between the Power Authority of the State of New York and NMPC as to sale, transmission and disposition of St. Lawrence power.	Z	13-11
10-2	--Agreement dated February 10, 1961 between the Power Authority of the State of New York and NMPC as to sale, transmission and disposition of Niagara redevelopment power.	DD	13-6
10-3	--Agreement dated July 26, 1961 between the Power Authority of the State of New York and NMPC supplemental to Exhibit 10-2.	DD	13-7
10-4	--Agreement dated as of March 23, 1973 between the Power Authority of the State of New York and NMPC as to the sale, transmission and disposition of Blenheim-Gilboa power.	OO	5-8
10-5	--Agreement dated January 23, 1970 between Consolidated Gas Supply Corporation (formerly named New York State Natural Gas Corporation) and NMPC.	KK	5-8
10-6a	--New York Power Pool Agreement dated as of February 1, 1974 between NMPC and six other New York utilities and the Power Authority of the State of New York.	QQ	5-10
10-6b	--New York Power Pool Agreement dated as of April 27, 1975 between NMPC and six other New York electric utilities and the Power Authority of the State of New York (the parties to the Agreement have petitioned the Federal Power Commission for an order permitting such Agreement, which increases the reserve factor of all parties from .14 to .18, to supersede the New York Power Pool Agreement dated as of February 1, 1974).	TT	5-10b
10-7	--Agreement dated as of October 31, 1968 between NMPC, Central Hudson Gas & Electric Corporation and Consolidated Edison Company of New York, Inc. as to Joint Electric Generating Plant (the Roseton Station).	JJ	5-10
10-8a	--Memorandum of Understanding dated as of May 30, 1975 between NMPC and Rochester Gas & Electric Corporation with respect to Oswego Unit No. 6.	SS	5-13
10-8b	--Memorandum of Understanding dated as of May 30, 1975 between NMPC and Rochester Gas and Electric Corporation with respect to Oswego Unit No. 6.	SS	5-13
10-8c	--Basic Agreement dated as of September 22, 1975 between NMPC and Rochester Gas and Electric Corporation with respect to Oswego Unit No. 6.	VV	5-13b
10-9a	--Memorandum of Understanding dated as of May 30, 1975 between NMPC and four other New York electric utilities with respect to Nine Mile Point Nuclear Station Unit No. 2.	SS	5-14

Exhibit No.	Description of Instrument	Incorporation by Reference: Previous Filing	Incorporation by Reference: Previous Exhibit Designation
10-9b	--Basic Agreement dated as of September 22, 1975 between NMPC and four other New York electric utilities with respect to Nine Mile Point Nuclear Station Unit No. 2.	w	5-14b
10-9c	--Nine Mile Point Nuclear Station Unit No. 2 Operating Agreement.	c	10-19
10-10a	--Memorandum of Understanding dated as of May 16, 1974, as amended May 30, 1975, between NMPC and three other New York electric utilities with respect to the Sterling Nuclear Station.	ss	5-15
10-10b	--Basic Agreement dated as of September 22, 1975 between NMPC and three other New York electric utilities with respect to the Sterling Nuclear Stations.	w	5-15b
10-11	--Master Restructuring Agreement, dated as of July 9, 1997, between the Company and the sixteen independent power producers signatory thereto.	n	10.28
10-12	--PowerChoice settlement filed with the PSC on October 10, 1997	o	99-9
*10-13	--PSC Opinion and Order regarding approval of the PowerChoice settlement agreement with PSC, issued and effective March 20, 1998.		
*10-14	--Preferred Consent, December, 1997		
(A)10-15	--NMPC Officers' Incentive Compensation Plan - Plan Document.	b	10-16
(A)10-16	--NMPC Long Term Incentive Plan - Plan Document.	l	10-1
(A)10-17	--NMPC Management Incentive Compensation Plan - Plan Document.	b	10-17
(A)10-18	--CEO Special Award Plan.	l	10-2
(A)10-19	--NMPC Deferred Compensation Plan.	d	10-16
*(A)10-20	--Amendment to NMPC Deferred Compensation Plan		
(A)10-21	--NMPC Performance Share Unit Plan.	d	10-17
(A)10-22	--NMPC 1992 Stock Option Plan.	d	10-18
(A)10-23	--NMPC 1995 Stock Incentive Plan	f	10-31
(A)10-24	--Employment Agreement between NMPC and David J. Arrington, Sr. Vice President, Human Resources, dated December 20, 1996.	g	10-17
(A)10-25	--Employment Agreement between NMPC and Albert J. Budney, Jr., President and Chief Operating Officer, dated December 20, 1996.	g	10-18
(A)10-26	--Employment Agreement between NMPC and William E. Davis, Chairman of the Board and Chief Executive Officer, dated December 20, 1996.	g	10-19

(A) Management contract or compensatory plan or arrangement required to be filed as an exhibit pursuant to Item 601 of Regulation S-K.

		Incorporation by Reference	
Exhibit No.	Description of Instrument	Previous Filing	Previous Exhibit Designation
(A)10-27	--Employment Agreement between NMPC and Darlene D. Kerr, Sr. Vice President, Energy Distribution, dated December 20, 1996.	g	10-20
(A)10-28	--Employment Agreement between NMPC and Gary J. Lavine, Sr. Vice President, Legal and Corporate Relations, dated December 20, 1996.	g	10-21
(A)10-29	--Employment Agreement between NMPC and John W. Powers, Sr. Vice President and Chief Executive Officer, dated December 20, 1996.	g	10-22
(A)10-30	--Employment Agreement between NMPC and B. Ralph Sylvia, Executive Vice President, Electric Generation and Chief Nuclear Officer, dated December 20, 1996.	g	10-23
(A)10-31	--Employment Agreement between NMPC and Theresa A. Flaim, Vice President - Corporate Strategic Planning, dated December 20, 1996.	g	10-24
(A)10-32	--Employment Agreement between NMPC and Steven W. Tasker, Vice President - Controller, dated December 20, 1996.	g	10-25
(A)10-33	--Employment Agreement between NMPC and Kapua A. Rice, Corporate Secretary, dated December 20, 1996.	g	10-26
(A)10-34	--Amendment to Employment Agreement between NMPC and David J. Arrington, Albert J. Budney, Jr., William E. Davis, Darlene D. Kerr, Gary J. Lavine, John W. Powers and B. Ralph Sylvia, dated June 9, 1997.	l	10-3
(A)10-35	--Employment Agreement between NMPC and William F. Edwards, dated September 25, 1997.	m	10-4
*(A)10-36	--Employment Agreement between NMPC and John H. Mueller, dated January 19, 1998.		
(A)10-37	--Deferred Stock Unit Plan for Outside Directors.	g	10-27
*11	--Statement setting forth the computation of average number of shares of common stock outstanding.		
*12	--Statements Showing Computations of Certain Financial Ratios.		
*21	--Subsidiaries of the Registrant.		
*23	--Consent of Price Waterhouse LLP, independent accountants.		
*27	--Financial Data Schedule.		

(A) Management contract or compensatory plan or arrangement required to be filed as an exhibit pursuant to Item 601 of Regulation S-K.

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARIES

COMPUTATION OF AVERAGE NUMBER OF SHARES OF COMMON STOCK OUTSTANDING

Year Ended December 31,	(1) Shares of Common Stock	(2) Number of Days Outstanding	(3) Share Days (2 x 1)	Average Number of Shares Outstanding as Shown on Consolidated Statements of Income (3 Divided by Number of Days in Year)
1997				
January 1 - December 31	144,365,214	365	52,693,303,110	
Shares issued at various times during the period -				
Acquisition - Syracuse Suburban Gas Company, Inc.	54,137	*	14,260,096	
	144,419,351		52,707,563,206	144,404,283
1996				
January 1 - December 31	144,332,123	366	52,825,557,018	
Shares issued at various times during the year -				
Acquisition - Syracuse Suburban Gas Company, Inc.	33,091	*	6,397,653	
	144,365,214		52,831,954,671	144,349,603
1995				
January 1 - December 31	144,311,466	365	52,673,685,090	
Shares issued-				
Dividend Reinvestment Plan - January 31	19,016	335	6,370,360	
Acquisition - Syracuse Suburban Gas Company, Inc. - October 4	1,641	89	146,049	
	144,332,123		52,680,201,499	144,329,319

* Number of days outstanding not shown as shares represent an accumulation of weekly, monthly and quarterly issues throughout the year. Share days for shares issued are based on the total number of days each share was outstanding during the year.

Note: Earnings per share calculated on both a basic and diluted basis are the same due to the effects of rounding.

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

Statement Showing Computations of Ratio of Earnings to Fixed Charges,
Ratio of Earnings to Fixed Charges without AFC and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Year Ended December 31,				
	1997	1996	1995	1994	1993
A. Net Income per Statements of Income	$59,835	$110,390	$248,036	$176,984	$271,831
B. Taxes Based on Income or Profits	60,095	66,221	159,393	111,469	147,075
C. Earnings, Before Income Taxes	119,930	176,611	407,429	288,453	418,906
D. Fixed Charges (a)	304,451	308,323	314,973	315,274	319,197
E. Earnings Before Income Taxes and Fixed Charges	424,381	484,934	722,402	603,727	738,103
F. Allowance for Funds Used During Construction	9,706	7,355	9,050	9,079	16,232
G. Earnings Before Income Taxes and Fixed Charges without AFC	$414,675	$477,579	$713,352	$594,648	$721,871
Preferred Dividend Factor:					
H. Preferred Dividend Requirements	$ 37,397	$ 38,281	$ 39,596	$ 33,673	$ 31,857
I. Ratio of Pre-Tax Income to Net Income (C / A)	2.00	1.60	1.64	1.63	1.54
J. Preferred Dividend Factor (H x I)	$ 74,794	$ 61,250	$ 64,937	$ 54,887	$ 49,060
K. Fixed Charges as above (D)	304,451	308,323	314,973	315,274	319,197
L. Fixed Charges and Preferred Dividends Combined	$379,245	$369,573	$379,910	$370,161	$368,257
M. Ratio of Earnings to Fixed Charges (E / D)	1.39	1.57	2.29	1.91	2.31
N. Ratio of Earnings to Fixed Charges without AFC (G / D)	1.36	1.55	2.26	1.89	2.26
O. Ratio of Earnings to Fixed Charges and Preferred Dividends Combined (E / L)	1.12	1.31	1.90	1.63	2.00

(a) Includes a portion of rentals deemed representative of the interest factor: $26,149 for 1997, $26,600 for 1996, $27,312 for 1995
$29,396 for 1994 and $27,821 for 1993.

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

Subsidiaries of the Registrant

Name of Company	State of Organization
Opinac North America, Inc. (Note 1)	Delaware
NM Uranium, Inc.	Texas
EMCO-TECH, Inc. (Note 2)	New York
NM Holdings, Inc. (Note 3)	New York
Moreau Manufacturing Corporation	New York
Beebee Island Corporation	New York
NM Receivables Corp.	New York

Note 1: At December 31, 1997, Opinac North America, Inc. owns Opinac Energy Corporation and Plum Street Enterprises, Inc. Opinac Energy Corporation has a 50 percent interest in CNP, which is incorporated in the Province of Ontario, Canada. CNP owns Cowley Ridge Partnership (an Alberta, Canada general partnership) and Canadian Niagara Wind Power Company, Inc. (incorporated in the Province of Alberta, Canada). Plum Street Enterprises, Inc., ("Plum Street") an unregulated company, is incorporated in the State of Delaware. Plum Street owns Plum Street Energy Marketing, Inc. (incorporated in the State of Delaware), Global Energy Enterprises India Private Limited, 90% of Dolphin Investments International, Inc. (a corporation organized and existing under the laws of Nevis, West Indies, which owns 45% of Atlantis Energie Systems AG (a corporation organized and existing under the laws of the Federal Republic of Germany)), 25% of Telergy Joint Venture and 26% of Direct Global Power, Inc.

Note 2: EMCO-TECH, Inc. is inactive at December 31, 1997.

Note 3: At December 31, 1997, NM Holdings, Inc. owns Salmon Shores, Inc., Moreau Park, Inc., Riverview, Inc., Hudson Pointe, Inc., Upper Hudson Development, Inc., Land Management & Development, Inc., OPropco, Inc. and LandWest, Inc.

EXHIBIT 23

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 33-36189, 33-42771 and 333-13781) and to the incorporation by reference in the Prospectus constituting part of the Registration Statement on Form S-3 (Nos. 33-50703, 33-51073, 33-54827 and 33-55546) of Niagara Mohawk Power Corporation of our report dated March 26, 1998 appearing in the Company's Form 10-K dated March 26, 1998. We also consent to the incorporation by reference of our report on the Financial Statement Schedule, which appears in this Form 10-K

Price Waterhouse LLP

PRICE WATERHOUSE LLP

Syracuse, New York
March 26, 1998

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NIAGARA MOHAWK POWER CORPORATION
(Registrant)

Date: March 26, 1998

By /s/ Steven W. Tasker
Steven W. Tasker
Vice President-Controller
and Principal Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ William F. Allyn William F. Allyn	Director	March 26, 1998
/s/ Albert J. Budney, Jr. Albert J. Budney, Jr.	Director, President	March 26, 1998
/s/ Lawrence Burkhardt, III Lawrence Burkhardt, III	Director	March 26, 1998
/s/ Douglas M. Costle Douglas M. Costle	Director	March 26, 1998
/s/ Edmund M. Davis Edmund M. Davis	Director	March 26, 1998
/s/ William E. Davis William E. Davis	Chairman of the Board of Directors and Chief Executive Officer	March 26, 1998

Signature	Title	Date
/s/ William J. Donlon William J. Donlon	Director	March 26, 1998
/s/ Anthony H. Gioia Anthony H. Gioia	Director	March 26, 1998
/s/ Bonnie Guiton Hill Bonnie Guiton Hill	Director	March 26, 1998
/s/ Henry A. Panasci, Jr. Henry A. Panasci, Jr.	Director	March 26, 1998
/s/ Patti McGill Peterson Patti McGill Peterson	Director	March 26, 1998
/s/ Donald B. Riefler Donald B. Riefler	Director	March 26, 1998
/s/ Stephen B. Schwartz Stephen B. Schwartz	Director	March 26, 1998
/s/ William F. Edwards William F. Edwards	Senior Vice President and Chief Financial Officer	March 26, 1998
/s/ Steven W. Tasker Steven W. Tasker	Vice President-Controller and Principal Accounting Officer	March 26, 1998

SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-K/A

Amendment No. 2

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1997

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission File Number: 1-2987

Niagara Mohawk Power Corporation

(Exact name of registrant as specified in its charter)

State of New York (State or other jurisdiction of incorporation or organization)	**15-0265555** (I.R.S. Employer Identification No.)
300 Erie Boulevard West Syracuse, New York (Address of principal executive offices)	**13202** (Zip Code)

(315) 474-1511
Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:
(Each class is registered on the New York Stock Exchange)

Title of each class
Common Stock ($1 par value)

Preferred Stock ($100 par value-cumulative):
3.40% Series 4.10% Series
3.60% Series 4.85% Series
3.90% Series 5.25% Series
6.10% Series
7.72% Series

Preferred Stock ($25 par value-cumulative):
9.50% Series
Adjustable Rate
Series A & Series C

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K [X]

State the aggregate market value of the voting stock held by non-affiliates of the registrant.
Approximately $1,800,000,000 at March 26, 1998.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common stock, $1 par value, outstanding at March 26, 1998 – 144,419,351

NIAGARA MOHAWK POWER CORPORATION
INFORMATION REQUIRED IN FORM 10-K/A

NIAGARA MOHAWK POWER CORPORATION

GLOSSARY OF TERMS

TERM	DEFINITION
AFC	Allowance for Funds Used During Construction
CNP	Canadian Niagara Power Company, Limited
COPS	Competitive Opportunities Proceeding
CTC	Competitive Transition Charges
DEC	New York State Department of Environmental Conservation
DOE	U. S. Department of Energy
Dth	Dekatherm: one thousand cubic feet of gas with a heat content of 1,000 British Thermal Units per cubic foot
EBITDA	Earnings before Interest Charges, Interest Income, Income Taxes, Depreciation and Amortization, Amortization of Nuclear Fuel, Allowance for Funds Used During Construction, MRA Regulatory Asset amortization, non-cash regulatory deferrals and other amortizations and extraordinary items (a non-GAAP measure of cash flow)
FAC	Fuel Adjustment Clause: a clause in a rate schedule that provides for an adjustment to the customer's bill if the cost of fuel varies from a specified unit cost
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GRT	Gross Receipts Tax
GWh	Gigawatt-hour: one gigawatt-hour equals one billion watt-hours
IPP	Independent Power Producer: any person that owns or operates, in whole or in part, one or more Independent Power Facilities
IPP Party	Independent Power Producers that are a party to the MRA

ISO	Independent System Operator
KW	Kilowatt: one thousand watts
KWh	Kilowatt-hour: a unit of electrical energy equal to one kilowatt of power supplied or taken from an electric circuit steadily for one hour
MERIT	Measured Equity Return Incentive Term
MRA	Master Restructuring Agreement - an agreement to terminate, restate or amend IPP Party power purchase agreements
MRA regulatory asset	Recoverable costs to terminate, restate or amend IPP Party contracts, which are deferred and amortized under PowerChoice
MW	Megawatt: one million watts
MWh	Megawatt-hour: one thousand kilowatt-hours
NRC	U. S. Nuclear Regulatory Commission
NYPA	New York Power Authority
NYPP	New York Power Pool
NYPP Member Systems	Eight Member Systems are: the seven New York State investor-owned electric utilities and NYPA
NYSERDA	New York State Energy Research and Development Authority
PowerChoice agreement	Company's five-year electric rate agreement, which incorporates the MRA, approved in February 1998
PPA	Power Purchase Agreement: long-term contracts under which a utility is obligated to purchase electricity from an IPP at specified rates
PRP	Potentially Responsible Party
PSC	New York State Public Service Commission
PURPA	Public Utility Regulatory Policies Act of 1978, as amended. One of five bills signed into law on November 8, 1978, as the National Energy Act. It sets forth procedures and requirements applicable to state utility commissions, electric and natural gas utilities and certain federal

	regulatory agencies. A major aspect of this law is the mandatory purchase obligation from qualifying facilities.
QF	Qualifying Facility: an individual (or corporation) that owns and/or operates a generating facility but is not primarily engaged in the generation or sale of electric power. QFs are either power production or cogeneration facilities that qualify under Section 201 of PURPA.
ROE	Return on Common Stock Equity
SFAS No. 71	Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 101	Statement of Financial Accounting Standards No. 101 "Regulated Enterprises - Accounting for the Discontinuance of Application of FASB Statement No. 71"
SFAS No. 106	Statement of Financial Accounting Standards No. 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS No. 109	Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes"
SFAS No. 121	Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of"
SFAS No. 130	Statement of Financial Accounting Standards No. 130 "Reporting Comprehensive Income"
SFAS No. 131	Statement of Financial Accounting Standards No. 131 "Disclosures about Segments of an Enterprise and Related Information"
SFAS No. 132	Statement of Financial Accounting Standards No. 132 "Employers' Disclosure about Pensions and Other Postretirement Benefits"
stranded costs	Utility costs that may become unrecoverable due to a change in the regulatory environment
Unit 1	Nine Mile Point Nuclear Station Unit No. 1
Unit 2	Nine Mile Point Nuclear Station Unit No. 2

NIAGARA MOHAWK POWER CORPORATION

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

The following table sets forth selected financial information of the Company for each of the five years during the period ended December 31, 1997, which has been derived from the audited financial statements of the Company, and should be read in connection therewith. As discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data - "Notes to Consolidated Financial Statements," the following selected financial data is not likely to be indicative of the Company's future financial condition or results of operations.

	1997	1996*	1995	1994	1993
Operations: (000's)					
Operating revenues	$ 3,966,404	$ 3,990,653	$ 3,917,338	$ 4,152,178	$ 3,933,431
Net income	183,335	110,390	248,036	176,984	271,831
Common stock data:					
Book value per share at year end	$18.89	$17.91	$17.42	$17.06	$17.25
Market price at year end	10 1/2	9 7/8	9 1/2	14 1/4	20 1/4
Ratio of market price to book value at year end	55.6%	55.1%	54.5%	83.5%	117.4%
Dividend yield at year end	-	-	11.8%	7.9%	4.9%
Basic and diluted earnings per average common share	$1.01	$ .50	$1.44	$1.00	$1.71
Rate of return on common equity	5.5%	2.8%	8.4%	5.8%	10.2%
Dividends paid per common share	-	-	$1.12	$1.09	$ .95
Dividend payout ratio	-	-	77.8%	109.0%	55.6%
Capitalization: (000's)					
Common equity	$ 2,727,527	$ 2,585,572	$ 2,513,952	$ 2,462,398	$ 2,456,465
Non-redeemable preferred stock	440,000	440,000	440,000	440,000	290,000
Mandatorily redeemable preferred stock	76,610	86,730	96,850	106,000	123,200
Long-term debt	3,417,381	3,477,879	3,582,414	3,297,874	3,258,612
TOTAL	6,661,518	6,590,181	6,633,216	6,306,272	6,128,277

	1997	1996*	1995	1994	1993
Long-term debt maturing within one year	67,095	48,084	65,064	77,971	216,185
TOTAL	$ 6,728,613	$ 6,638,265	$ 6,698,280	$ 6,384,243	$ 6,344,462
Capitalization ratios: (including long-term debt maturing within one year)					
Common stock equity	40.5%	39.0%	37.5%	38.6%	38.7%
Preferred stock	7.7	7.9	8.0	8.5	6.5
Long-term debt	51.8	53.1	54.5	52.9	54.8
Financial ratios:					
Ratio of earnings to fixed charges	2.02	1.57	2.29	1.91	2.31
Ratio of earnings to fixed charges and preferred stock dividends	1.67	1.31	1.90	1.63	2.00
Other ratios - % of operating revenues:					
Fuel, electricity purchased and gas purchased	44.4%	43.5%	40.3%	39.6%	36.1%
Other operation and maintenance expenses	21.1	23.3	20.9	23.1	26.9
Depreciation and amortization	8.6	8.3	8.1	7.4	7.0
Federal and foreign income taxes, and other taxes	15.1	13.6	17.3	14.7	16.2
Operating income	14.1	13.1	17.5	13.3	17.5
Balance available for common stock	3.7	1.8	5.3	3.5	6.1
Miscellaneous: (000's)					
Gross additions to utility plant	$ 290,757	$ 352,049	$ 345,804	$ 490,124	$ 519,612
Total utility plant	11,075,874	10,839,341	10,649,301	10,485,339	10,108,529
Accumulated depreciation and amortization	4,207,830	3,881,726	3,641,448	3,449,696	3,231,237
Total assets	9,584,141	9,427,635	9,477,869	9,649,816	9,471,327

* Amounts include extraordinary item, see Note 2. Rate and Regulatory Issues and Contingencies.

NIAGARA MOHAWK POWER CORPORATION

Certain statements included in this Annual Report on Form 10-K are forward-looking statements as defined in Section 21E of the Securities Exchange Act of 1934, including the hedge against upward movement in market prices provided by the restructured and amended PPAs, the improvement in operating cash flows as a result of the MRA and PowerChoice, the recoverability of the MRA regulatory asset through the prices charged for electric service, the effect of a PSC natural gas proposal on the Company's results of operations, expected earnings over the five-year term of the PowerChoice agreement, the effect of the elimination of the FAC under PowerChoice on the Company's financial condition, the reduction in net income resulting from the non-cash amortization of the MRA regulatory asset, the effect of the January 1998 ice storm damage restoration costs on the Company's capital requirements, recoverability of environmental compliance costs and nuclear decommissioning costs through rates, and the improvement in the Company's financial condition expected as a result of the MRA and the implementation of PowerChoice. The Company's actual results and developments may differ materially from the results discussed in or implied by such forward-looking statements, due to risks and uncertainties that exist in the Company's operations and business environment, including, but not limited to, matters described in the context of such forward-looking statements, as well as such other factors as set forth in the Notes to Consolidated Financial Statements contained herein.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EVENTS AFFECTING 1997 AND THE FUTURE

- On July 9, 1997, the Company announced the MRA to terminate, restate or amend IPP power purchase contracts in exchange for cash, shares of the Company's common stock and certain financial contracts. The terms of the MRA have been and may continue to be modified.

- In February 1998, the PSC approved the PowerChoice settlement agreement, which incorporates the terms of the MRA. Under PowerChoice, a regulatory asset will be established for the costs of the MRA and it will be amortized over a period generally not to exceed ten years. The Company's rates under PowerChoice are designed to permit recovery of the MRA regulatory asset. In approving PowerChoice, the PSC limited the estimated value of the MRA regulatory asset that can be recovered to approximately $4,000 million, which is expected to result in a charge to the second quarter of 1998 earnings of $190.0 million or 85 cents per share upon the closing of the MRA. The PowerChoice agreement, while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.

- In December 1997, the preferred shareholders gave the Company approval to increase the amount of unsecured debt that the Company may issue by $5 billion. This authorization enables the issuance of unsecured debt to consummate the MRA.

- The PowerChoice agreement calls for the Company to conduct an auction to sell all of its fossil and hydro generation assets.

- In early January 1998, a major ice storm caused extensive and costly damage to the Company's facilities in northern New York.

MASTER RESTRUCTURING AGREEMENT AND THE POWERCHOICE AGREEMENT

The Company entered into the PPAs that are subject to the MRA because it was required to do so under PURPA, which was intended to provide incentives for businesses to create alternative energy sources. Under PURPA, the Company was required to purchase electricity generated by qualifying facilities of IPPs at prices that were not expected to exceed the cost that otherwise would have been incurred by the Company in generating its own electricity, or in purchasing it from other sources (known as "avoided costs"). While PURPA was a federal initiative, each state retained certain delegated authority over how PURPA would be implemented within its borders. In its implementation of PURPA, the State of New York passed the "Six-Cent Law," establishing 6 cents per KWh as the floor on avoided costs for projects less than 80 MW in size. The Six-Cent Law remained in place until it was amended in 1992 to deny the benefit of the statute to any future PPAs. The avoided cost determinations under PURPA were periodically increased by the PSC during this period. PURPA and the Six-Cent Law, in combination with other factors, attracted large numbers of IPPs to New York State, and, in particular, to the Company's service territory, due to the area's existing energy infrastructure and availability of cogeneration hosts. The pricing terms of substantially all of the PPAs that the Company entered into in compliance with PURPA and the Six-Cent Law or other New York laws were based, at the option of the IPP, either on administratively determined avoided costs or minimum prices, both of which have consistently been materially higher than the wholesale market prices for electricity.

Since PURPA and the Six-Cent Law were passed, the Company has been required to purchase electricity from IPPs in quantities in excess of its own demand and at prices in excess of that available to the Company by internal generation or for purchase in the wholesale market. In fact, by 1991, the Company was facing a potential obligation to purchase power from IPPs substantially in excess of its peak demand of 6,093 MW. As a result, the Company's competitive position and financial performance have deteriorated and the price of electricity paid per KWh by its customers has risen significantly above the national average. Accordingly, in 1991 the Company initiated a parallel strategy of negotiating individual PPA buyouts, cancellations and renegotiations, and of pursuing regulatory and legislative support and litigation to mitigate the Company's obligation under the PPAs. By mid-1996, this strategy had resulted in reducing the capacity of the Company's obligations to purchase power under its PPA portfolio to approximately 2,700 MW. Notwithstanding this reduction in capacity, over the same period the payments made to the IPPs under their PPAs rose from approximately $200 million in 1990 to approximately $1.1 billion in 1997 as independent power facilities from which the Company was obligated to purchase electricity commenced operations. The Company estimates that absent the MRA, payments made to the IPPs pursuant to PPAs would continue to escalate by approximately $50 million per year until 2002.

Recognizing the competitive trends in the electric utility industry and the impracticability of remedying the situation through a series of customer rate increases, in mid-1996 the Company began comprehensive negotiations to terminate, amend or restate a substantial portion of above-market PPAs in an effort to mitigate the escalating cost of these PPAs as well as to prepare the Company for a more competitive environment. These negotiations led to the MRA and the PowerChoice agreement.

MASTER RESTRUCTURING AGREEMENT. On July 9, 1997, the Company entered into the MRA with 16 IPP Parties who sell electricity to the Company under 29 PPAs. The MRA specifically contemplated that two IPPs, Oxbow Power of North Tonawanda, New York, Inc. ("Oxbow") and NorCon would enter into further negotiations concerning their treatment under the MRA. Following such negotiations, Oxbow has withdrawn from the MRA, but, based on the value of its allocation under the MRA and the terms of its existing PPA, Oxbow's withdrawal does not materially impact the cost reductions associated with the MRA. The Company and NorCon have agreed to replace NorCon's initial allocation under the MRA with an all cash allocation which has, in the Company's estimation, a value approximately $60 million higher than NorCon's initial allocation. A third IPP Party has agreed to take cash in exchange for the shares of common stock allocated to it in the MRA. As a result of these cash allocations, there are 3,054,000 fewer shares of common stock allocated to the IPPs under the MRA. The MRA has been amended to expire on July 15, 1998.

The MRA currently provides for the termination, restatement or amendment of 28 PPAs with 15 IPPs, which represent approximately 80% of the Company's over-market purchased power obligations, in exchange for an aggregate of $3,616 million in cash and 42.9 million shares of the Company's common stock and certain financial contracts. The closing of the MRA is subject to a number of conditions, including the Company and the IPP Parties negotiating individual restated and amended contracts, the receipt of all regulatory approvals, the receipt of all consents by third parties necessary for the transactions contemplated by the MRA (including the termination of the existing PPAs and the termination or amendment of all related third party agreements), the IPP Parties entering into new third party arrangements which will enable each IPP Party to restructure its projects on a reasonably satisfactory economic basis, the Company having completed all necessary financing arrangements and the Company and the IPP Parties having received all necessary approvals from their respective boards of directors, shareholders and partners. While one or more of the IPP Parties may under certain circumstances terminate the MRA with respect to itself, the Company's obligation to close the MRA is subject to its determination that as a result of any such terminations the benefits anticipated to be received by the Company pursuant to the MRA have not been materially and adversely affected. The Company expects that prior to the consummation of the MRA, the mix of consideration to be received by the IPP Parties may be renegotiated. The foregoing is qualified in its entirety by the text of the MRA (see Exhibit 10-11). As the Conditions Determination Date (the date by which all IPP Parties must satisfy or waive their third party conditions or withdraw from the MRA) has not occurred, the Company cannot predict whether such conditions will be satisfied, whether some IPP Parties may withdraw, whether the terms of the MRA might be renegotiated, or whether the MRA will be consummated. In the event the Company is unable to successfully complete the MRA and therefore implement PowerChoice, it would pursue all alternatives including a traditional rate request.

The principal effects of the MRA are to reduce significantly the Company's existing payment obligations under the PPAs, which currently consist of approximately 2,700 MW of capacity at December 31, 1997. While earnings will be depressed during the five-year term, the savings in annual energy payments, coupled with the rates established in PowerChoice, will yield free cash flow that can be dedicated to the new debt service obligations associated with the payment of cash to the IPP Parties.

Under the terms of the MRA, the Company's significant long term and escalating IPP payment obligations will be restructured into a defined and more manageable obligation and a portfolio of restated and amended PPAs with price and duration terms that the Company believes are more favorable than the existing PPAs. Under the MRA, 19 PPAs representing approximately 1,180 MW of capacity will be terminated completely thus allowing this capacity to be replaced through the competitive market at market based prices. The Company has no continuing obligation to purchase energy from the terminating IPP Parties.

Also under the MRA, 8 PPAs representing approximately 541 MW of capacity will be restated on economic terms and conditions that are more favorable to the Company than the existing PPAs. The restated contracts have a term of 10 years and are structured as financial swap contracts where the Company receives or makes payments to the IPP Parties based upon the differential between the contract price and a market reference price for electricity. The contract prices are fixed for the first two years changing to an indexed pricing formula thereafter. Contract quantities are fixed for the full 10 year term of the contracts. The indexed pricing structure ensures that the price paid for energy and capacity will fluctuate relative to the underlying market cost of gas and general indices of inflation. Until such time as a competitive energy market structure becomes operational in the State of New York, the restated contracts provide the IPP Parties with a put option for the physical delivery of energy. Additionally, one PPA representing 42 MW of capacity will be amended to reflect a shortened term and a lower stream of fixed unit prices. Finally, the MRA requires the Company to provide the IPP Parties with a number of fixed price swap contracts with a term of seven years beginning in 2003. The fixed price swap contracts will be cash settled monthly based upon a stream of defined quantities and prices.

Although against the Company's forecast of market energy prices the restructured and amended PPAs represent an expected above-market payment obligation, the Company's portfolio of these PPAs provides it and its customers with a hedge against significant upward movement in market prices that may be caused by a change in energy supply or demand. This portfolio and market purchases contain terms that are believed to be more responsive to competitive market price changes. (See Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Long-term Contracts for the Purchase of Electric Power").

POWERCHOICE AGREEMENT. The PowerChoice agreement establishes a five-year rate plan that will reduce average residential and commercial rates by an aggregate of 3.2% over the first three years. This reduction will include certain savings that will result from partial reductions of the New York State GRT. Industrial customers will see average reductions of 25% relative to 1995 price levels; these decreases will include discounts currently offered to some industrial customers through optional and flexible rate programs. The cumulative rate reductions, net of GRT savings, are estimated to be approximately $112 million, to be experienced on a generally ratable basis over the first three years of the agreement. During the term of the PowerChoice agreement, the Company will be permitted to defer certain costs, associated primarily with environmental remediation, nuclear decommissioning and related costs, and changes in laws, regulations, rules and orders. In years four and five of its rate plan, the Company can request an annual increase in prices subject to a cap of 1% of the all-in price, excluding commodity costs (e.g., transmission, distribution, nuclear, and forecasted CTC). In addition to the price cap, the PowerChoice agreement provides for the recovery of deferrals established in years one through four and cost variations in the MRA financial contracts resulting from indexing provisions of these contracts. The aggregate of the price cap increase and recovery of deferrals is subject to an overall limitation of inflation.

Under the terms of the PowerChoice agreement, all of the Company's customers will be able to choose their electricity supplier in a competitive market by December 1999. The Company will continue to distribute electricity through its distribution and transmission facilities and would be obligated to be the so-called provider of last resort for those customers who do not exercise their right to choose a new electricity supplier.

The PowerChoice agreement provides that the MRA and the contracts executed pursuant thereto shall be found to be prudent. The PowerChoice agreement further provides that the Company shall have a reasonable opportunity to recover its stranded costs, including those associated with the MRA and the contracts executed thereto, through a CTC and, under certain circumstances, through exit fees or in rates for back up service.

Under the PowerChoice agreement, an MRA regulatory asset, aggregating approximately $4,000 million, will be established. In this way, the costs of the MRA would be deferred and amortized over a period generally not to exceed ten years. The Company's rates under PowerChoice are designed to permit recovery of the MRA regulatory asset and to permit recovery of, and a return on, the remainder of its assets, as appropriate. The PowerChoice agreement, while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.

The PowerChoice agreement calls for the Company to divest all of its fossil and hydro generation assets. Divestiture is intended to be accomplished through an auction. Winning bids would be selected within 11 months of PSC approval of the auction plan, which was filed with the PSC separately from the PowerChoice agreement. The Company will receive a portion of the auction sale proceeds as an incentive to obtain maximum value in the sale. This incentive would be recovered from sale proceeds. The Company agreed that if it does not receive an acceptable bid for an asset, the Company will form a subsidiary to hold any such assets and then legally separate this subsidiary from the Company through a spin- off to shareholders or otherwise. If a bid of zero or below is received for an asset, the Company may keep the asset as part of its regulated business. The auction process will serve to quantify any stranded costs associated with the Company's fossil and hydro generating assets. The Company will have a reasonable opportunity to recover these costs through the CTC and otherwise as described above. After the auction process is complete, the Company has agreed not to own any non-nuclear generating assets in the State of New York, subject to certain exceptions provided in the PowerChoice agreement. Under the terms of the note indenture prepared in connection with the financing of the MRA, the Company will be required to use a majority of the cash portion of net proceeds from the sale of its fossil and hydro generating assets to reduce indebtedness. Such restrictions would not apply in the event that the Company was unable to successfully conclude the consummation of the MRA and therefore of PowerChoice but nonetheless sold such assets.

The PowerChoice agreement contemplates that the Company's nuclear plants will remain part of the Company's regulated business. The Company has been supportive of the creation of a statewide New York Nuclear Operating Company that it expects would improve the efficiency of nuclear units throughout the state. The PowerChoice agreement stipulates that absent such a statewide solution, the Company will file a detailed plan for analyzing other proposals regarding its nuclear assets, including the feasibility of an auction, transfer and/or divestiture of such facilities, within 24 months of PowerChoice approval.

The PowerChoice agreement also allows the Company to form a holding company at its election. The Company plans to seek its shareholders' approval at its 1998 annual meeting to the formation of a holding company, the implementation of which would only occur following various regulatory approvals.

At its public session on February 24, 1998, the PSC voted to approve the PowerChoice agreement, which incorporates the terms of the MRA. Subject to the satisfaction of the conditions to the MRA, the PSC's approval of PowerChoice should allow the Company to consummate the MRA in the first half of 1998. The PowerChoice agreement will only become effective upon the closing of the MRA. In approving PowerChoice, the PSC made the following changes, among others, to the agreement: i) customers who had made a substantial investment in on-site generation as of October 10, 1997 will be grandfathered and not have to pay the CTC; ii) savings from any reduction in the interest rate associated with the debt issued in connection with the MRA financing as compared to assumptions underlying the Company's PowerChoice filing will be deferred for future disposition; and iii) change the generation auction incentive to 15% of proceeds in excess of net book value for non- Oswego assets and 5% of proceeds in excess of $100 million for Oswego assets.

In its written order dated March 20, 1998, the PSC made several other changes to the PowerChoice agreement, in addition to those discussed at the February 24 session. The PSC determined to limit the estimated value of the MRA regulatory asset that can be recovered from customers, to approximately $4,000 million. The estimated value of the MRA regulatory asset includes the issuance of 42.9 million shares of common stock, which the PSC, in determining the recoverable amount of such asset valued at $8 per share. The Company's common stock closed at $12 7/16 per share on March 26, 1998. The accounting implications of the limitation on value are discussed under "Accounting Implications of the PowerChoice Agreement and Master Restructuring Agreement." The PSC also modified the reduction in average residential and commercial rates. The PowerChoice agreement measured the 3.2% reduction against 1995 prices. The PSC determined that the percentage reduction should be applied against the lower of 1995 prices or the most current twelve-month period. To the extent prices for the most current twelve-month period are lower than 1995 prices, the amount of cumulative rate reductions described below will increase. Lastly, the PSC ordered the Company not to proceed to consummate the MRA with respect to one contract held by one developer until a satisfactory resolution of a cogeneration steam host contract is reached.

New York law provides parties the right to appeal the Commission's decision approving the PowerChoice agreement within four months of the date of that decision. In addition, parties have the right to petition the Commission for rehearing of the decision within 30 days of the date of the decision. If a petition for rehearing is filed and the Commission issues a decision on rehearing, parties may appeal the decision on rehearing within four months of the date of the decision on rehearing. Such an appeal or petition for rehearing may be based on the failure of the record to show a reasonable basis for the terms of the PowerChoice agreement and may result in an amendment of the record to correct such failure, in renegotiation of such terms or in renegotiation of the PowerChoice agreement as a whole. There can be no assurance that, on appeal or on rehearing, the approval of the PowerChoice agreement will be upheld or that such appeal or rehearing will not result in terms substantially less favorable to the Company than those described herein.

All of the foregoing discussion of the PowerChoice agreement is qualified in its entirety by the text of the agreement and PSC Order (see Exhibits 10-12 and 10-13).

ACCOUNTING IMPLICATIONS OF THE POWERCHOICE AGREEMENT AND MASTER RESTRUCTURING AGREEMENT

The Company concluded as of December 31, 1996, that the termination, restatement or amendment of IPP contracts and implementation of PowerChoice was the probable outcome of negotiations that had taken place since the PowerChoice announcement. Under PowerChoice, the separated non-nuclear generation business would no longer be rate-regulated on a cost-of-service basis and, accordingly, regulatory assets related to the non-nuclear power generation business, amounting to approximately $103.6 million ($67.4 million after tax or 47 cents per share) were charged against 1996 income as an extraordinary non-cash charge.

As described under "Master Restructuring Agreement and the PowerChoice Agreement," the PSC in its written order issued March 20, 1998 limited the estimated value of the MRA regulatory asset that can be recovered from customers to approximately $4,000 million. The ultimate amount of the regulatory asset to be established may vary based on certain events related to the closing of the MRA. The estimated value of the MRA regulatory asset includes the issuance of 42.9 million shares of common stock, which the PSC, in determining the recoverable amount of such asset valued at $8 per share. Because the value of the consideration to be paid to the IPP Parties can only be determined at the MRA closing, the alue of the limitation on the recoverability of the MRA regulatory asset is expected to be recorded as a charge to expense in the second quarter of 1998 upon the closing of the MRA. The charge to expense will be determined as the difference between $8 per share and the Company's closing common stock price on the date the MRA closes, multiplied by 42.9 million shares. Using the Company's common stock price on March 26, 1998 of 12 7/16 per share, the charge to expense would be approximately $190 million (85 cents per share).

Under PowerChoice, the Company's remaining electric business (nuclear generation and electric transmission and distribution business) will continue to be rate-regulated on a cost-of-service basis and, accordingly, the Company continues to apply SFAS No. 71 to these businesses. Also, the Company's IPP contracts, including those restructured under the MRA and those not so restructured will continue to be the obligations of the regulated business. As described under "Master Restructuring Agreement and the PowerChoice Agreement," the consummation of the MRA, as well as implementation of PowerChoice, is subject to a number of contingencies.

The Emerging Issues Task Force ("EITF") of the FASB reached a consensus on Issue No. 97-4 "Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101" in July 1997. The Company discontinued the application of SFAS No. 71 and applied SFAS No. 101 with respect to the fossil and hydro generation business at December 31, 1996, in a manner consistent with the EITF consensus.

In addition, EITF 97-4 does not require the Company to earn a return on regulatory assets that arise from a deregulating transition plan in assessing the applicability of SFAS No. 71. In the event the MRA and PowerChoice are implemented, the Company believes that the regulated cash flows to be derived from prices it would charge for electric service over 10 years, including the CTC, assuming no unforeseen reduction in demand or bypass of the CTC or exit fees, will be sufficient to recover the MRA regulatory asset and provide recovery of and a return on the remainder of its assets, as appropriate. In the event the Company could no longer apply SFAS No. 71 in the future, it would be required to record an after-tax non-cash charge against income for any remaining unamortized regulatory assets and liabilities. Depending on when SFAS No. 71 was required to be discontinued, such charge would likely be material to the Company's reported financial condition and results of operations and the Company's ability to pay common and preferred dividends. The PowerChoice agreement while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.

In the event the Company is unable to successfully complete the MRA and therefore implement PowerChoice, it would pursue all alternatives including a traditional rate request. However, notwithstanding such a rate request, it is likely that application of SFAS No. 71 would be discontinued for the remaining electric business, since the Company's current rate structure would no longer be sufficient to recover its costs. The resulting non-cash after-tax charges against income, based on regulatory assets and liabilities associated with the nuclear generation and electric transmission and distribution businesses as of December 31, 1997, would be approximately $526.5 million or $3.65 per share. In addition, the Company would be required to reassess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. SFAS No. 121 requires long-lived assets and certain identifiable intangibles held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable or when assets are to be disposed of. In performing the review for recoverability, the Company is required to estimate future undiscounted cash flows expected to result from the use of the asset and/or its disposition. The Company would also be required to determine the extent to which adverse purchase commitments, if any, are required to be recorded as obligations. Various requirements under applicable law and regulations and under corporate instruments, including those with respect to issuance of debt and equity securities, payment of common and preferred dividends, and certain types of transfers of assets could be adversely impacted by any such write-downs.

With the implementation of PowerChoice, specifically the separation of non-nuclear generation as an entity that would no longer be cost-of-service regulated, the Company is required to assess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. The Company has determined that there is no impairment of its fossil and hydro generating assets. To the extent the proceeds resulting from the sale of the fossil and hydro assets are not sufficient to avoid a loss, the Company would be able to recover such loss through the CTC. The PowerChoice agreement provides for deferral and future recovery of losses, if any, resulting from the sale of the non-nuclear generating assets. The Company believe that it will be permitted to record a regulatory asset for any such loss in accordance with EITF 97-4. The Company's fossil and hydro generation plant assets had a net book value of approximately $1.1 billion at December 31, 1997.

PSC COMPETITIVE OPPORTUNITIES PROCEEDING - ELECTRIC

On May 16, 1996, the PSC issued its Order in the COPS case, which called for a major restructuring of New York State's electric industry. The COPS order called for a competitive wholesale power market and the introduction of retail access for all electric customers. The goals cited in its decision included lowering consumer rates, increasing choice, continuing reliability of service, continuing environmental and public policy programs, mitigating concerns about market power and continuing customer protection and the obligation to serve.

The PSC decision in the COPS proceeding states that recovery of utility stranded costs may be accomplished by a non-bypassable "wires charge" to be imposed by distribution companies. The PSC decision also states that a careful balancing of customer and utility interests and expectations is necessary, and that the level of stranded cost recovery will ultimately depend upon the particular circumstances of each utility.

On June 10, 1997, the PSC ordered a multi-utility, retail access pilot program that would allow qualified farmers and food processors to shop for electricity and other energy services. The PSC required utilities to adjust the current delivery rates for farmers and food processors, which resulted in rate reductions of about 10 percent for farmers and 3 percent to 6 percent for food processors. Delivery under this program began in late 1997. The Company does not believe that this order will have a material adverse effect on its financial position or results of operations.

On August 27, 1997, the PSC requested comments on its staff's tentative conclusions about how nuclear generation and fossil generation should be treated after decisions are made on the individual electric restructuring agreements currently pending before the PSC. The PSC staff concluded that beyond the transition period (the period covered by the individual restructuring agreements including PowerChoice), nuclear generation should operate on a competitive basis. In addition, the PSC staff concluded that a sale of generation plants to third parties is the preferred means of determining the fair market value of generation plants and offers the greatest potential for the mitigation of stranded costs. The PSC staff also concluded that recovery of sunk costs, including post shutdown costs, would be subject to review by the PSC and this process should take into account mitigation measures taken by the utility, including the steps it has taken to encourage competition in its service area. The Company's nuclear generation assets had a net book value of $1.5 billion (excluding the reserve for decommissioning) at December 31, 1997.

In October 1997, the majority of utilities with interests in nuclear power plants, including the Company, requested that the PSC reconsider its staff's nuclear proposal. In addition, the utilities raised the following issues: impediments to nuclear plants operating in a competitive mode; impediments to the sale of plants; responsibility for decommissioning and disposal of spent fuel; safety and health concerns; and environmental and fuel diversity benefits. In light of all of these issues, the utilities recommended that a more formal process be developed to address those issues.

The three investor-owned utilities, Rochester Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. and the Company, which are currently pursuing formation of a nuclear operating company in New York State, also filed a response with the PSC in October 1997. The response stated that a forced divestiture of the nuclear plants would add uncertainty to developing a statewide approach to operating the plants and requested that such a forced divestiture proposal be rescinded. The response also stated that implementation of a consolidated six-unit operation would contribute to the mitigation of unrecovered nuclear costs. The NYPA, which is also pursuing formation of the nuclear operating company, submitted its own comments which were similar to the comments of the three utilities.

In February 1998, the PSC established a formal proceeding to further examine issues related to nuclear plants and the feasibility of applying market-based pricing to these facilities.

See "Master Restructuring Agreement and PowerChoice Agreement" above for a discussion of the treatment of nuclear operations during the term of PowerChoice.

FERC RULEMAKING ON OPEN ACCESS AND STRANDED COST RECOVERY

In April 1996, the FERC issued FERC Order 888. Order 888 promotes competition by requiring that public utilities owning, operating, or controlling interstate transmission facilities file tariffs which offer others the same transmission services they provide for themselves, under comparable terms and conditions. The Company has complied with this requirement by filing its open access transmission tariff with FERC on July 7, 1996. Based upon settlement discussions with various parties, a proposed settlement was submitted to the FERC in the first quarter of 1997. The settlement has not been approved by the FERC at this time. Hearings were conducted in September 1997 with non-settling parties. A March 1998 Administrative Law Judge's recommended decision in this proceeding recommended lower tariffs than those filed by the Company. The Company is unable to determine the ultimate resolution of this issue or when a decision will be issued by FERC.

Under FERC Order 888, the NYPP was required to file reformed power pooling agreements that establish open, non-discriminatory membership provisions and modify any provisions that are unduly discriminatory or preferential. On January 31, 1997, the NYPP Member Systems (the

"Member Systems") submitted a comprehensive proposal to establish an ISO, a New York State Reliability Council ("NYSRC") and a New York Power Exchange ("NYPE") that will foster a fully competitive wholesale electricity market in New York State. The ISO would provide for the reliable operation of the transmission system in New York State and provide nondiscriminatory open access to transmission services under a single ISO tariff. Through the ISO, the transmission owners, including the Company, would be compensated for the use of their transmission systems on a cost-of-service basis. The NYSRC would establish the reliability rules and standards by which the ISO operates the bulk power system. The ISO would also administer the daily electric energy market and the NYPE would facilitate the electric energy market on a day-ahead basis. On May 2, 1997, the Member Systems made a supplemental filing related to the proposed NYSRC and on August 15, 1997, six of the Member Systems filed an application for market-based rate authority in the new wholesale market structure. On December 19, 1997, the Member Systems submitted a revised filing which reflected the fundamental components of the initial January 31, 1997 filing. However, the December 19, 1997 filing provides for additional explanatory materials, incorporates FERC's guidance set forth in FERC orders involving other power pools and ISOs, and sets forth a revised governance structure of the ISO. The Company is unable to predict when FERC will act on these submittals, or whether it will approve the filings with or without modifications. However, the Company's PowerChoice agreement does not condition retail access on the presence of an ISO.

In Order 888, the FERC also stated that it would provide for the recovery of prudent and verifiable wholesale stranded costs where the wholesale customer was able to obtain alternative power supplies as a result of Order 888's open access mandate. Order 888 left to the states the issue of retail stranded cost recovery. Where newly created municipal electric utilities required transmission service from the displaced utility, the FERC stated that it would entertain requests for stranded cost recovery since such municipalization is made possible by open access. The FERC also reserved the right to consider stranded costs on a case-by- case basis if it appeared that open access was being used to circumvent stranded cost review by any regulatory agency.

Numerous parties, including the Company, filed requests for rehearing of Order 888. In March 1997, the FERC issued Order 888- A, which generally affirmed Order 888 and granted rehearing on only a handful of issues. One of those issues was whether the FERC would review stranded costs in annexation cases as it committed to do in municipalization cases. In Order 888-A the FERC stated that it would review stranded costs resulting from territorial annexation by an existing municipal electric system, provided that system relied on transmission from the displaced utility. The FERC denied the Company's request for rehearing on how stranded costs would be calculated and other issues. In November 1997, FERC issued Order 888-B. This Order largely affirmed the positions set forth in Order 888-A while clarifying that the FERC recognizes the existence of concurrent state jurisdiction over stranded costs arising from municipalization. The FERC acknowledged in Order 888- B that the states may be first to address the issue of retail- turned-wholesale stranded costs, and stated that it will give the states substantial deference where they have done so.

In late January 1997, the Company provided 26 communities in St. Lawrence and Franklin counties with estimates they requested of the stranded costs they might be expected to pay if they withdraw from the Company's system to create government-controlled utilities. The preliminary estimate of the combined potential stranded cost liability for the communities ranges from a low of $225 million to a high of $452 million, depending upon the forecast of electricity market prices that is used. These amounts do not include the costs of creating and operating a municipal utility. At this time, 21 of the original 26 communities are still pursuing the matter. If these 21 communities withdrew from the Company's system, the Company would experience a potential revenue loss of approximately $60 million to $65 million per year. In addition, the Company is aware of other communities that are considering municipalization. However, the Company is unable to predict whether those communities would pursue municipalization.

The stranded cost calculations were based on a methodology prescribed by the FERC. Because no municipality has moved forward with condemnation, the value of the Company's facilities has not been deducted from the stranded cost estimates. The stranded costs included in these estimates are the communities' share of obligations that were incurred on behalf of all customers to fulfill the Company's legal obligations to ensure adequate, reliable electricity service. Such legitimate and prudent costs are currently included in electricity rates. Government-mandated payments to IPPs represent the largest single component of these costs. These 21 communities seeking to withdraw from the Company's system also propose to disconnect entirely from the Company's system and to take transmission service from another utility. They believe that, given the provisions of Order 888, FERC would not approve the Company's request for stranded cost recovery under these circumstances. The Company has responded that, regardless of the result at the FERC, opportunities for stranded cost recovery in this matter could also be pursued before the PSC and in a state condemnation proceeding. (See "Master Restructuring Agreement and the PowerChoice Agreement.") The Company is unable to predict the outcome of this matter.

OTHER FEDERAL AND STATE REGULATORY INITIATIVES

PSC PROPOSAL OF NEW IPP OPERATING AND PPA MANAGEMENT PROCEDURES. In August 1996, the PSC proposed to examine the circumstances under which a utility, including the Company, may legally curtail purchases from IPPs; whether utilities should be permitted to collect data that will assist in monitoring IPPs' compliance with federal QF requirements, upon which the mandated purchases are predicated; and if utilities should be allowed to demand security from IPPs to ensure the repayment of amounts accumulated in tracking accounts made under their purchased power contracts.

The PSC noted that some of the current IPP contracts are far above market prices and are causing utilities to seek rate increases. In addition, the PSC stated that its proposal was initiated to protect ratepayers, since it would ensure just and reasonable rates in the event ongoing negotiations between utilities and IPPs fail.

MONITORING. In December 1996, the PSC gave the New York State utilities, including the Company, the authority to collect data to assist them in monitoring IPPs' compliance with both federal QF standards and state requirements. The PSC stated that if QFs are not meeting requirements, the obligation to pay the full contract rate, which is funded by utility ratepayers, is generally excused or mitigated. Furthermore, if the data collected through a QF monitoring program indicates a facility is not meeting federal standards, the utility could petition the FERC to decertify the QF, which could result in penalties that could include cancellation of the contract. A similar penalty could be imposed if it is determined a QF has failed to maintain compliance with state law. Under the monitoring program, QFs are required to submit data as of March 1 each year for the previous calendar year. In accordance with the terms of the MRA, the Company will not implement any QF monitoring program for the IPP Parties. However, the Company continues to monitor those IPPs that are not IPP Parties for continued QF compliance under PSC regulation.

CURTAILMENT. On May 20, 1997, the PSC addressed the procedures under which a utility, including the Company, may legally curtail purchases from IPPs that are QFs, unless curtailment is specifically prohibited by contract. Curtailment is allowed by a FERC rule, under certain operational circumstances when purchases from the QFs will exceed the costs the utility would incur if it generated the power itself. Advance notice must be provided to the QF along with the reasons for such curtailment, which are subject to verification by the PSC either before or after curtailment. The PSC stated that PURPA, which encouraged generation by IPPs, was supposed to be revenue-neutral. However, they noted that this has not been the situation in New York State and ratepayers have been unduly burdened because of their lack of specific curtailment procedures.

The decision to permit curtailment is not likely to affect the PPAs covered by the MRA, which represents approximately 80% of the Company's over-market purchased power obligations, as described previously. However, the decision could affect most of the remaining IPP contracts. The Company is unable to determine the effect of these statements until such a time as there is a final order.

The Company cannot predict whether the PSC will take any action on the firm security issue. However, the firm security issue with respect to the IPP Parties covered under the MRA would be settled upon the closing of the MRA.

MULTI-YEAR GAS RATE SETTLEMENT AGREEMENT. The Company, Multiple Intervenors (an unincorporated association of approximately 60 large commercial and industrial energy users with manufacturing and other facilities located throughout New York State) and PSC staff reached a three-year settlement that was conditionally approved by the PSC on December 19, 1996. The PSC ordered conditional approval on the three-year settlement agreement until a final, redrafted agreement, which reflects the Commission's order, is submitted for final approval. The settlement results in a $10 million annual reduction in base rates or a $30 million total reduction over the three-year term of the settlement. This reflects a $19 million reduction in the amount of fixed non- commodity costs to be recoverable in base rates, offset by a $9 million increase in annual base rates. The Company estimates that the combination of in-hand supplier refunds and further reductions in upstream pipeline costs will be sufficient to fund the $19 million annual reduction in non-commodity cost recovery.

If the non-commodity cost reductions exceed $57 million ($19 million annually) during the three-year settlement period, the excess, up to $40 million will be credited to a Contingency Reserve Account ("CRA") to be utilized for ratepayer benefit in the rate year ending October 31, 2000 or beyond. To the extent the actual non-commodity cost reductions exceed $57 million by more than $40 million, the Company may retain any excess subject to a return on equity sharing provision. In the event the non-commodity reductions fall short of the $57 million estimate, the Company will bear the risk of any shortfall. In the event that the termination or restructuring of IPP contracts results in margin (revenues less fuel costs) or peak shaving losses, the margin losses would be collected currently subject to 80%/20% (ratepayer/shareholder) sharing and the peak shaving losses will be deferred to the CRA, subject to limits specified in the settlement.

In return for taking on this risk, the Company has achieved a portion of the revised rate structure that had been proposed to reduce its throughput risk. The Company obtained an ROE cap of 13.5% with 50/50 sharing between ratepayers and shareholders in excess of the cap. The Company also has an opportunity to earn up to $2.25 million annually if its gas commodity costs are lower than a market based target without being subject to the ROE cap. The Company has an equal $2.25 million risk if gas commodity costs exceed the target. An additional major benefit of the revised rate design is that the margin made on each additional new customer will significantly increase to the extent additional throughput does not require additional upstream pipeline capacity for service. This, along with the approval of the Company's Progress Fund, which allows the Company to use utility revenues in an amount not to exceed $11 million in total for the purpose of providing financing for large customers to convert or increase their gas use, will provide new opportunities for growth.

GENERIC GAS RATE PROCEEDING. As a result of the generic rate proceeding, in which the PSC ordered all New York utilities to implement a service unbundling beginning in May 1996, nearly 3,000 customers have chosen to buy natural gas from other sources, with the Company continuing to provide transportation service for a separate fee. These changes have not had a material impact on the Company's margins since the margin is traditionally derived from the delivery service and not from the commodity sale. The margin for delivery for residential and commercial aggregation services equals the margin on the traditional sales service classes. To date this migration has not resulted in any stranded costs since the PSC has allowed the utilities to assign the pipeline capacity to the customers converting from sales to transportation. This assignment is allowed during a three-year period ending March 1999, at which time the PSC will decide on methods for dealing with the remaining unassigned or excess capacity. As a part of the generic rate proceeding, all utilities are required to file a report with the PSC in April 1998, describing actions that have been taken to mitigate potential stranded costs as customers migrate to transportation service. In a clarifying order in this proceeding, issued September 4, 1997, the PSC has indicated that it is unlikely that utilities will be allowed to continue to assign pipeline capacity to departing customers after March 1999.

On a separate but parallel path, in September 1997, the PSC issued for comment its staff's position paper on the future of the natural gas industry, including recommendations for increasing competition and expanding customer choice in the natural gas marketplace. The staff proposed, among other things, that all regulated natural gas utilities exit the business of purchasing natural gas for customers over the next five years. This would complete the transition of customers from sales to transportation service only. The regulated utilities would only deliver natural gas purchased by customers from competitive suppliers. If this proposal is adopted by the PSC, then it would eliminate the need to regulate natural gas purchasing practices since market forces would establish natural gas prices.

The position paper identified a number of issues that would need to be resolved in order for this proposal to be successful. The primary issues are the pipeline capacity and gas supply contracts that the local utilities have with interstate pipelines that extend beyond the proposed five-year transition period, the obligation of the utility to serve as supplier of last resort, and the issue of system reliability.

The Company and other parties submitted comments and reply comments to the PSC in late November and December of 1997, respectively. With the exception of the issues to be resolved by the PSC, as mentioned above, the Company does not believe that this proposal will have a material adverse effect on its results of operations or financial condition, since the Company's natural gas margin is derived from the delivery service and not from the commodity sale. The resolution of the issues identified by the PSC could result in unrecovered stranded costs for the Company. The Company is unable to predict how the PSC will resolve those issues. For a discussion of the Company's gas supply, storage and pipeline commitments, see Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Gas Supply, Storage and Pipeline Commitments.")

NRC AND NUCLEAR OPERATING MATTERS. In October 1996, the NRC required companies with nuclear plants to provide the NRC with added confidence and assurance that their plants are operated and maintained within the design basis, and any deviations are reconciled in a timely manner. Such information, which was filed within the required 120 days, will be used by the NRC to verify that companies are in compliance with the terms and conditions of their license(s) and NRC regulations. In addition, it will allow the NRC to determine if other inspection activities or enforcement actions should be taken on a particular company.

In the letter transmitting the requested information to the NRC, the Company concluded that it has reasonable assurance that (i) design basis requirements are being translated into operating, maintenance, and testing procedures; and (ii) system, structure and component configuration and performance are consistent with the design basis. Also, the Company has an effective administrative tool for the identification, documentation, notification, evaluation, correction, and reporting of conditions, events, activities, and concerns that have the potential for adversely affecting the safe and reliable operation of Unit 1 and Unit 2.

In April 1997 and December 1997, the Company received notices from the NRC of a $200,000 fine and $50,000 fine, respectively, for violations at Unit 1 and Unit 2. The penalties were for violations related to corrective actions and design control. The Company paid the fines and is implementing corrective action. On January 23, 1998, the Company received notice of a proposed $55,000 fine from the NRC for violations of NRC requirements related to radioactive waste issues. The Company does not plan to contest the proposed NRC fine.

In January 1998, the NRC issued its Systematic Assessment of Licensee Performance (the "SALP") report on Unit 1 and Unit 2, which covers the period June 1996 to November 1997. The SALP report, which is an extensive assessment of the plants' performance in the areas of operations, maintenance, engineering and support, stated that the performance of Unit 1 and Unit

2 was generally good, although ratings were lower than the previous assessment. The Company agrees with the NRC's determination that there are areas of its performance that need improvement and is taking several actions to make those needed improvements.

The Company believes that NRC safety enforcement is becoming more stringent as indicated by the NRC's request for information, fines that the Company has been assessed and lower SALP ratings and that there may be a direct cost impact on companies with nuclear plants as a result. The Company is unable to predict how such a changed operating environment may affect its results of operations or financial condition.

Some owners of older General Electric Company boiling water reactors, including the Company, have experienced cracking in horizontal welds in the plants' core shrouds. In response to industry findings, the Company installed pre-emptive modifications to the Unit 1 core shroud during a 1995 refueling and maintenance outage. The core shroud, a stainless steel cylinder inside the reactor vessel, surrounds the fuel and directs the flow of reactor water through the fuel assemblies.

Inspections conducted as part of the March 1997 refueling and maintenance outage detected cracking in vertical welds not reinforced by the 1995 repairs. On April 8, 1997, the Company filed a comprehensive inspection and analysis report with the NRC that concluded that the condition of the Unit 1 core shroud supports the safe operation of the plant.

On May 8, 1997, the NRC approved the Company's request to operate Unit 1 until the next scheduled mid-cycle outage, late 1998. The Company agreed to propose an inspection plan for the outage and submit the plan to the NRC at least three months before the outage is scheduled to begin. The Company believes it has a strong technical basis to operate Unit 1 without a mid-cycle outage and is seeking the necessary approval from the NRC to postpone the inspections until the unit's refueling and maintenance outage in spring 1999, but there can be no assurance that such approval will be granted.

The Unit 1 refueling and maintenance outage, originally planned to be completed in early April 1997, was completed on May 10, 1997 due to the core shroud issue. On September 15, 1997, Unit 1 was taken out of service due to leaking in one of four back-up condensers. The standby condensers serve as a back-up system for the removal of reactor steam. The condensers are maintained in a ready state during normal plant operations. Tests and inspections were conducted on the remaining condensers and similar conditions were found. On December 10, 1997, Unit 1 was returned to service after the replacement of all four condensers, which cost approximately $6.7 million.

OTHER COMPANY EFFORTS TO ADDRESS COMPETITIVE CHALLENGES

TAX INITIATIVES. The Company is working with utility, customer and state representatives to explain the negative impact that all utility taxes, including the GRT, are having on rates and the state of the economy. At the same time, the Company is also contesting the high real estate taxes it is assessed by many taxing authorities, particularly those imposed upon generating facilities.

The New York State Legislature passed a state budget in August 1997 which includes a reduction of the GRT over three years. For gas and electric utilities, the tax imposed on gross income will be reduced from 3.5% to 3.25% on October 1, 1998, and from 3.25% to 2.5% on January 1, 2000. The state tax imposed on gross earnings will remain unchanged at .75%, bringing the total GRT to 3.25% -- a full percentage point lower than today's level of 4.25%. The savings from the reduction of the GRT will be passed on to the Company's customers. The Company believes that further tax relief is needed to relieve the Company's customers of high energy costs and to improve New York State's competitive position as the industry moves toward a competitive marketplace.

The following table sets forth a summary of the components of other taxes (exclusive of income taxes) incurred by the Company in the years 1995 through 1997:

	In millions of dollars		
	1997	1996	1995
Property tax expense	$250.7	$249.4	$264.8
Sales tax	13.4	14.1	13.9
Payroll tax	34.1	36.4	37.3
Gross Receipts Tax	184.6	184.1	190.2
Other taxes	0.1	0.5	5.2
Total tax expense	482.9	484.5	511.4
Charged to construction, subsidiaries and regulatory recognition	(11.4)	(8.7)	6.1
Total other taxes	$471.5	$475.8	$517.5

CUSTOMER DISCOUNTS. In recent years, some industrial customers have found alternative suppliers or are generating their own power. In addition, a weakened economy or attractive energy prices elsewhere have contributed to other industrial customer decisions to relocate or close.

In addressing the threat of further loss of industrial load, the PSC established guidelines to govern flexible electric rates offered by utilities to retain qualified industrial customers. Under these guidelines, the Company filed for a new service tariff in August 1994 (SC-11), under which all new contract rates are administered based on demonstrated industrial and commercial competitive pricing alternatives including, but not limited to, on- site generation, fuel switching, facility relocation and partial plant production shifting. Contracts are for terms not to exceed seven years without PSC approval. In addition, the Company has economic development programs which provide tariff based incentives to retain and grow load.

As of January 1998, the Company has 152 executed contracts under its flexible tariff offerings. These contracts have been signed to mitigate the lost margin impacts associated with customers executing the competitive alternatives mentioned above. In addition, many of these contracts include an increase in production levels and/or attract new customers to the Company's service territory.

In 1997 and 1996, the total amount of customer discounts (economic development programs and flexible pricing) was $90.6 million and $75.5 million, respectively. The Company recovered $46.6 million and $56.7 million in rates, respectively. Pending implementation of PowerChoice, the Company budgeted its discounts to increase to approximately $95.4 million in 1998 as some discounts granted in 1997 are in effect for an entire year and further discounts are granted. The Company is aggressively using SC-11 to increase sales to existing customers and to attract new customers to its service territory. With the reduction in industrial prices provided in PowerChoice, the level of discounts that have been necessary should decline in the future.

REGULATORY AGREEMENTS/PROPOSALS

(See "Master Restructuring Agreement and the PowerChoice Agreement.")

1995 RATE ORDER. On April 21, 1995, the Company received a rate decision (1995 rate order) from the PSC which approved an approximately $47 million increase in electric revenues and a $4.9 million increase in gas revenues.

YEAR 2000 COMPUTER ISSUE

As the year 2000 approaches, the Company, along with many other companies, could experience potentially serious operational problems, since many computer programs that were developed will not properly recognize calendar dates beginning with the year 2000. Further, there are embedded chips contained within generation, transmission, distribution and gas equipment that may be date- sensitive. In these circumstances where an embedded chip fails to recognize the correct date, electric or gas operations could be adversely affected. The Company is addressing these issues so that its computer systems and, where necessary, its embedded chips will process dates greater than 1999, thereby preventing any adverse operational or financial impacts. The Company has been addressing the year 2000 information technology issue through the remediation and replacement of existing business applications and parts of its technical infrastructure. In late 1997, the services of a leading computer services and consulting firm were retained to conduct an assessment of the Company's entire year 2000 program. As a result of the assessment, a Company-wide year 2000 project management office has been formed and year 2000 project managers have been appointed within each business group and efforts are underway to evaluate the scope of the problem for embedded technologies/process control systems in all business groups within the Company. A Company-wide program director and an executive level steering committee have been put in place to oversee all aspects of the program. The Company is also evaluating the exposure to year 2000 problems of third parties with whom the Company conducts business. The Company expects to complete an inventory of exposures, including an assessment of priorities, costs and resources, by the third quarter of 1998. Failures of the Company and/or third party computer systems and embedded chips could have a material impact on the Company's ability to conduct its business. Until further progress is made on these efforts, management is unable to estimate the total year 2000 compliance expense, but it is in the process of assessing this expense.

RESULTS OF OPERATIONS

Earnings for 1997 were $145.9 million, or $1.01 per share, as compared to $72.1 million, or 50 cents per share, in 1996 and $208.4 million, or $1.44 per share, in 1995. In comparing year-to-year results, earnings in 1996 reflect certain significant events that were not repeated in 1997. Earnings in 1996 were reduced by an after-tax write-off of $67.4 million, or 47 cents per share, associated with the discontinued application of regulatory accounting principles to the Company's fossil and hydro generation business. Largely as a result of the Company's 1996 assessment of the increased risk of collecting significantly higher levels of past-due customer bills, bad debt expense in 1996 was higher than in 1997 by $81.1 million, reducing earnings in 1996, compared to 1997, by 37 cents per share. However, earnings in 1996 were aided by a $15 million after-tax gain on the sale of a 50 percent interest in CNP which added 10 cents per share to 1996 earnings. Industrial customer discounts not recovered in rates in 1997 exceeded 1996 levels by $25.2 million, reducing 1997 earnings by 11 cents per share (see Other Company Efforts to Address Competitive Challenges - "Customer Discounts.") In addition, a decline in higher-margin residential sales also adversely impacted 1997 earnings. The lower-margin industrial-special sales (sales by the Company on behalf of NYPA) and industrial sales increased. As a result, total public sales were essentially the same as sales in 1996.

Earnings for 1995 were hurt by lower sales quantities of electricity and natural gas, as compared with amounts used to establish 1995 prices. Sales were primarily affected by the continuing weak economic conditions in upstate New York, loss of industrial customers' load to NYPA and discounts granted. These factors similarly impacted 1996 and 1997 results. In addition, 1995 earnings included the recording of a one-time, non-cash adjustment of prior years' demand-side management ("DSM") incentive revenues, revenues earned under the Unit 1 operating incentive sharing mechanism and a gain on the sale of HYDRA-CO that collectively increased 1995 earnings by 17 cents per share.

The Company's 1997 earned ROE was 5.5% as compared to 2.8% (5.4% before extraordinary loss) in 1996 and 8.4% in 1995. The Company's ROE authorized in the 1995 or last rate setting process is 11.0% for the electric business and 11.4% for the gas business. Factors contributing to earnings below authorized levels in 1997 included, among other things, sales below those forecasted in determining rates, contractual increases in capacity payments to IPPs and increasing discounts to customers. As discussed under "Master Restructuring Agreement and the PowerChoice Agreement" and "Accounting Implications of the PowerChoice Agreement and Master Restructuring Agreement," the Company forecasts that earnings for the five-year term of the PowerChoice agreement will be substantially depressed. The level of earnings for 1998 will also be impacted, in part, by the date of implementation of PowerChoice, the PowerChoice charge of $190 million expected to be taken in the second quarter of 1998 and may also be negatively impacted by the financial effects of the January 1998 ice storm (see Item 8. Financial Statements and Supplementary Data - "Note 13. Subsequent Event").

The following discussion and analysis highlights items that significantly affected operations during the three-year period ended December 31, 1997. This discussion and analysis is not likely to be indicative of future operations or earnings, particularly in view of the probable termination, restatement or amendment of IPP contracts and implementation of PowerChoice. It also should be read in conjunction with Item 8. Financial Statements and Supplementary Data and other financial and statistical information appearing elsewhere in this report.

ELECTRIC REVENUES were $3,309 million in both 1997 and 1996, a decrease of $26.1 million, or 0.8% from 1995. As shown in the following table, FAC revenues increased $42.8 million in 1997, primarily as a result of the Company's ability in 1997 to recover increased payments to the IPPs through the FAC. However, this increase was offset by a decrease in revenues from sales to other electric systems and lower electric sales due to warmer weather. Under PowerChoice, revenues may decline as customers choose alternative suppliers. However, the Company will recover stranded costs through the CTC. See "Master Restructuring Agreement and the PowerChoice Agreement."

Electric operating revenues decreased in 1996, primarily due to a decrease in miscellaneous electric revenues. Miscellaneous electric revenues were lower in 1996 primarily because 1995 electric revenues included the recording of $71.5 million of unbilled, non-cash revenues in accordance with the 1995 rate order, $13.0 million of revenues earned under MERIT (an incentive mechanism related to improvement in key performance areas which ended in 1996) and a one-time, non-cash adjustment of prior year's DSM incentive revenues and a reduction in the DSM rebate cost program. However, higher electric sales due to colder weather, an increase in sales to other electric systems, an increase in FAC revenues and higher electric rates (effective April 26, 1995) partly offset those factors that contributed to lower electric revenues. FAC revenues increased $28.3 million in 1996, which primarily reflects the Company's increased payments to the IPPs recovered through the FAC.

INCREASE (DECREASE) FROM PRIOR YEAR
(In millions of dollars)

ELECTRIC REVENUES	1997	1996	TOTAL
<S>	<C>	<C>	<C>
Amortization of unbilled revenues	$ -	$ (77.1)	$ (77.1)
Base rates	-	65.3	65.3
Fuel adjustment clause revenues	42.8	28.3	71.1
Changes in volume and mix of sales to ultimate consumers	(12.7)	(28.1)	(40.8)
Sales to other electric systems	(29.6)	24.5	(5.1)
MERIT revenue	-	(13.0)	(13.0)
DSM revenue	-	(26.5)	(26.5)
	$ 0.5	$ (26.6)	$ (26.1)

The FAC is eliminated under the PowerChoice agreement. Changes in FAC revenues are generally margin-neutral (subject to an incentive mechanism discussed in Item 8. Financial Statements and Supplementary Data - "Note 1. Summary of Significant Accounting Policies"), while sales to other utilities, because of regulatory sharing mechanisms and relatively low prices, generally result in low margin contributions to the Company. Thus, fluctuations in these revenue components do not generally have a significant impact on net operating income. Electric revenues reflect the billing of a separate factor for DSM programs, which provided for the recovery of program related rebate costs.

ELECTRIC KILOWATT-HOUR SALES were 37.1 billion in 1997, 39.1 billion in 1996 and 37.7 billion in 1995. The 1997 decrease of 2.0 billion KWh, or 5.1% as compared to 1996, is related primarily to a 31.0% decrease in sales to other electric systems. (See Item 8. Financial Statements and Supplementary Data -"Electric and Gas Statistics - Electric Statistics"). The 1996 increase of 1.4 billion KWh, or 3.8% as compared to 1995, reflects a 26.2% increase in sales to other electric systems and a 1.2% increase in sales to ultimate customers due to the colder weather. Sales to other electric systems were lower primarily due to a reduction in the availability of nuclear generation as a result of the outages at Unit 1. The Company is anticipating little or no growth in 1998 in sales to ultimate consumers, which will be sensitive to the business climate in its service territory.

Details of the changes in electric revenues and KWh sales by customer group are highlighted in the table below:

CLASS OF SERVICE	1997 % OF ELECTRIC REVENUES	% INCREASE (DECREASE) FROM PRIOR YEAR 1997 REVENUES	1997 SALES	1996 REVENUES	1996 SALES
Residential	37.1%	(2.0)%	(2.0)%	3.1%	0.5%
Commercial	37.3	(0.3)	(0.1)	-	(0.4)
Industrial	16.1	1.2	0.6	0.2	1.2
Industrial-Special	1.9	5.8	4.2	3.9	6.7
Municipal service	1.6	1.4	(4.5)	5.8	7.4
Total to ultimate consumers	94.0	(0.6)	-	1.4	1.2
Other electric systems	2.5	(26.1)	(31.0)	27.5	26.2
Miscellaneous	3.5	70.4	(100.0)	(57.8)	(17.7)
TOTAL	100.0%	-%	(5.1)%	(0.8)%	3.8%

As indicated in the table below, internal generation decreased 10.1% in 1997, principally due to the outage at Unit 1 and a reduction in hydroelectric power as a result of lower than normal precipitation in the summer months. In 1997, Unit 1 was out of service for 153 days, due to a planned refueling and maintenance outage (which took 68 days) and for the emergency condenser replacement (which took approximately 85 days) while in 1996, Unit 2 was out of service for a 36 day planned refueling and maintenance outage. (See "Other Federal and State Regulatory Initiatives - NRC and Nuclear Operating Matters.") The amount of electricity delivered to the Company by the IPPs decreased by approximately 277 GWh or 2.0%. However, total IPP costs increased by approximately $18.0 million or 1.7%, as discussed below. (See "Master Restructuring Agreement and the PowerChoice Agreement").

(In millions of dollars)	1997 GWh	1997 Cost	1996 GWh	1996 Cost	1995 GWh	1995 Cost	% Change from Prior Year 1997 to 1996 GWh	1997 to 1996 Cost	1996 to 1995 GWh	1996 to 1995 Cost
Fuel for electric generation:										
Coal	7,459	$ 106.4	7,095	$ 100.6	6,841	$ 97.9	5.1%	5.8%	3.7%	2.8%
Oil	701	32.2	462	21.1	537	21.3	51.7	52.6	(14.0)	(0.9)
Natural gas	394	8.6	319	9.2	996	20.2	23.5	(6.5)	(68.0)	(54.5)
Nuclear	6,339	33.0	8,243	47.7	7,272	43.3	(23.1)	(30.8)	13.4	10.2
Hydro	2,905	-	3,679	-	2,971	-	(21.0)	-	23.8	-
	17,798	180.2	19,798	178.6	18,617	182.7	(10.1)	0.9	6.3	(2.2)
Electricity purchased:										
IPPs:										
Capacity	-	220.8	-	212.8	-	181.2	-	3.8	-	17.4
Energy and taxes	13,520	885.7	13,797	875.7	14,023	798.7	(2.0)	1.1	(1.6)	9.6
Total IPP purchases	13,520	1,106.5	13,797	1,088.5	14,023	979.9	(2.0)	1.7	(1.6)	11.1
Other	9,421	130.2	9,569	130.6	9,463	126.5	(1.5)	(0.3)	1.1	3.2
	22,941	1,236.7	23,366	1,219.1	23,486	1,106.4	(1.8)	1.4	(0.5)	10.2
Total generated and purchased	40,739	1,416.9	43,164	1,397.7	42,103	1,289.1	(5.6)	1.4	2.5	8.4
Fuel adjustment clause	-	(1.3)	-	(33.3)	-	14.8	-	(96.1)	-	(325.0)
Losses/Company use	3,603	-	4,037	-	4,419	-	(10.8)	-	(8.6)	-
	37,136	$1,415.6	39,127	$1,364.4	37,684	$1,303.9	(5.1)%	3.8%	3.8%	4.6%

The above table presents the total costs for purchased electricity, while reflecting only fuel costs for Company generation. Other costs of generation, such as taxes, other operating expenses and depreciation are included within other income statement line items.

The Company's management of its IPP power supply generally divides the projects into three categories: hydroelectric, "must run" cogeneration and schedulable cogeneration projects.

Following a higher than normal spring run off, the precipitation in the summer months was lower than usual. As a result, hydroelectric IPP projects delivered 242 GWh or 13.7% less under PPAs than they did for the same period last year, representing decreased payments to those IPPs of $15.7 million.

A substantial portion of the Company's portfolio of IPP projects operate on a "must run" basis. This means that they tend to run at maximum production levels regardless of the need for or economic value of the electricity produced. Output from "must run" cogeneration IPPs was 230 GWh or 2.6% lower than produced last year, in part due to lower energy purchases from the Sithe Independence plant. However, payments to those IPPs were $12.8 million higher. This was due to a combination of output turndown arrangements with individual projects and escalating contract rates. A turndown arrangement is an agreement where the Company compensates an IPP to reduce the output from their facility. Although output is reduced, the net economic impact is favorable to the Company and its customers since the electricity is replaced from the market or other lower cost sources.

Quantities purchased from schedulable cogeneration IPPs increased 195 GWh or 6.3% and payments increased $20.9 million. The increased payments are largely due to escalating contract rates for capacity (fixed) and increased volumes of energy. The terms of these PPAs allow the Company to schedule (with certain constraints) energy deliveries and pay for the energy supplied. In addition, the Company is required to make fixed payments if the IPP plants remain available for service. (See Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Long-term Contracts for the Purchase of Electric Power").

GAS REVENUES decreased by $24.7 million, or 3.6% in 1997, and increased by $99.9 million, or 17.2%, in 1996. As shown in the table below, gas revenues decreased in 1997 primarily due to decreased sales to ultimate customers as a result of the migration of commercial sales customers to the transportation class, decreased spot market sales and a decrease in base rates of $5.9 million in accordance with the 1996 rate order. This was partially offset by higher gas adjustment clause recoveries and an increase in revenues from the transportation of customer-owned gas (see "Other Federal and State Regulatory Initiatives -Generic Gas Rate Proceeding").

Gas revenues increased in 1996 primarily due to increased sales to ultimate customers due to colder weather, increased spot market sales, higher gas adjustment clause recoveries, an increase in revenues from the transportation of customer-owned gas and an increase in base rates of $3.1 million in accordance with the 1995 rate order.

Rates for transported gas (excluding aggregation services) yield lower margins than gas sold directly by the Company. Therefore, increases in the volume of gas transportation services have not had a proportionate impact on earnings, particularly in instances where customers that took direct service from the Company move to a transportation-only class. In addition, changes in purchased gas adjustment clause revenues are generally margin- neutral.

GAS REVENUES	INCREASE (DECREASE) FROM PRIOR YEAR (In millions of dollars) 1997	1996	TOTAL
Base rates	$ (5.9)	$ 3.1	$ (2.8)
Transportation of customer-owned gas	5.3	2.1	7.4
Purchased gas adjustment clause revenues	45.3	30.8	76.1
Spot market sales	(30.8)	34.0	3.3
Changes in volume and mix of sales to ultimate consumers	(38.6)	29.9	(8.8)
	$(24.7)	$ 99.9	$ 75.2

GAS SALES, excluding transportation of customer-owned gas and spot market sales, were 78.7 million Dth in 1997, a 7.3% decrease from 1996, and a 0.3% increase from 1995. (See Item 8. Financial Statements and Supplementary Data - "Electric and Gas Statistics - Gas Statistics"). The decrease in 1997 was in all ultimate consumer classes, in part due to the warmer weather. In addition, spot market sales (sales for resale), which are generally from the higher priced gas available to the Company and therefore yield margins that are substantially lower than traditional sales to ultimate customers, decreased 8.0 million Dth. This was partially offset by an increase in transportation volumes of 18.1 million Dth or 13.5% to customers purchasing gas directly from producers. The Company has experienced an increase in customers of approximately 17,800 since 1995, primarily in the residential class, an increase of 3.5%.

Changes in gas revenues and Dth sales by customer group are detailed in the table below:

CLASS OF SERVICE	1997 % OF GAS REVENUES	% INCREASE (DECREASE) FROM PRIOR YEAR 1997 REVENUES	1997 SALES	1996 REVENUES	1996 SALES
Residential	66.4%	4.5%	(2.7)%	13.3%	9.4%
Commercial	22.6	(8.7)	(13.0)	13.0	6.4
Industrial	1.0	(50.9)	(50.1)	15.6	4.1
Total to ultimate consumers	90.0	(0.3)	(7.3)	13.3	8.3
Other gas systems	-	(5.8)	(6.7)	(81.9)	(81.4)
Transportation of customer-owned gas	8.5	10.5	13.5	4.3	(6.9)
Spot market sales	1.0	(82.9)	(76.6)	1,099.1	507.0
Miscellaneous	0.5	263.1	-	(82.2)	-
TOTAL	100.0%	(3.6)%	1.7%	17.2%	2.3%

The total cost of gas purchased decreased 6.6% in 1997 and increased 34.0% in 1996. The cost fluctuations generally correspond to sales volume changes, as spot market sales activity decreased, as well as changes in gas prices. The Company sold 2.5, 10.5 and 1.7 million Dth on the spot market in 1997, 1996 and 1995, respectively. The total cost of gas decreased $24.4 million in 1997. This was the result of a 5.3 million decrease in Dth purchased and withdrawn from storage for ultimate consumer sales ($18.8 million) and a $22.5 million decrease in Dth purchased for spot market sales, partially offset by a 3.3% increase in the average cost per Dth purchased ($10.7 million) and a $6.3 million increase in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause.

The total cost of gas purchased increased $93.8 million in 1996. This was the result of a 9.3 million increase in Dth purchased and withdrawn from storage for ultimate consumer sales ($29.6 million), a $25.6 million increase in Dth purchased for spot market sales and a 12.9% increase in the average cost per Dth purchased ($38.7 million). Gas purchased for spot market sales decreased $22.5 million in 1997 and increased $25.6 million in 1996. The Company's net cost per Dth sold, as charged to expense and excluding spot market purchases, increased to $3.82 in 1997 from $3.62 in 1996 and was $3.17 in 1995.

Through the electric and purchased gas adjustment clauses, costs of fuel, purchased power and gas purchased, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company's electric FAC provides for a partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. The Company absorbed losses of approximately $11.8 million, $1.4 million and $13.1 million in 1995, 1996 and 1997, respectively. Under PowerChoice, the FAC will be terminated. The Company does not believe that the elimination of the FAC will have a material adverse effect on its financial condition, as a result of its management of (1) power supplies provided through: (i) the operation of its own power plants, and future power purchase arrangements as part of the planned auction of its fossil and hydro assets, (ii) fixed power purchases from NYPA and remaining IPPs and (iii) fixed and indexed swap arrangements with IPP Parties and (2) the transfer of the risk associated with electricity commodity prices to the customer through implementation of retail access included in the PowerChoice agreement.

OTHER OPERATION AND MAINTENANCE EXPENSE decreased in 1997 by $92.9 million, or 10.0%, as compared to an increase of $110.3 million or 13.5% in 1996. These changes in 1996 and 1997 each result primarily from a change in 1996 in the Company's assessment of uncollectible customer accounts, which gives greater recognition to the increased risk of collecting past due customer bills, resulting in increases in the Company's allowance for doubtful accounts and a significantly higher expense recognition in 1996. Bad debt expense was $31.2 million, $127.6 million and $46.5 million in 1995, 1996 and 1997, respectively. In 1997, write-offs were $39.0 million and the Company incurred a $10.5 million increase in allowance for doubtful accounts. The increase in the allowance for doubtful accounts was attributable to increases in the collection risk associated with residential accounts receivable and arrears. The Company has implemented a number of collection initiatives that are expected to result in lower arrears levels and potentially lower the allowance for doubtful accounts. Other operation and maintenance expense also decreased in 1997 as a result of a reduction in administrative and general expenses of $15.8 million, primarily due to a reduction in legal costs.

OTHER INCOME decreased by $10.9 million in 1997 and increased by $32.9 million in 1996. Despite higher interest income ($12.0 million) related to increasing cash balances, "other income" was lower in 1997, since 1996 reflected a gain on the sale of a 50% interest in CNP ($15.0 million). The 1996 increase also reflected higher interest income ($10.9 million) as a result of an increase in temporary cash investments. In addition, "other income" was higher in 1996 since there were customer service penalties and certain other items written off because they were disallowed in rates in 1995.

FEDERAL AND FOREIGN INCOME TAXES increased by $24.1 million in 1997 primarily due to an increase in pre-tax income and decreased by $56.9 million in 1996 primarily due to a decrease in pre-tax income. Other taxes decreased by $4.4 million in 1997 and decreased by $41.6 million in 1996. The 1997 decrease was primarily due to lower payroll taxes ($2.3 million) and lower sales taxes ($0.7 million). The 1996 decrease was primarily as a result of lower real estate taxes ($15.4 million), lower GRTs ($6.1 million) primarily due to a reduction in the GRT surcharge during 1996, lower New York State excess dividend tax accrual due to a suspension of the common stock dividend ($4.6 million) and year-to- year differences in the accounting for regulatory deferrals ($15.2 million) associated primarily with a settlement of tax issues with respect to the Company's Dunkirk facility.

INTEREST CHARGES remained fairly constant for the years 1995 through 1997. However, dividends on preferred stock decreased by $0.9 million and $1.3 million in 1997 and 1996, respectively. Dividends on preferred stock decreased in 1997 primarily due to a reduction in preferred stock outstanding through sinking fund redemptions and decreased in 1996 primarily due to a decrease in the cost of variable rate issues. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 7.81% and 7.04%, respectively, in 1997 from 7.71% and 7.09%, respectively, in 1996 and from 7.77% and 7.19%, respectively, in 1995.

EFFECTS OF CHANGING PRICES

The Company is especially sensitive to inflation because of the amount of capital it typically needs and because its prices are regulated using a rate base methodology that reflects the historical cost of utility plant.

The Company's consolidated financial statements are based on historical events and transactions when the purchasing power of the dollar was substantially different than now. The effects of inflation on most utilities, including the Company, are most significant in the areas of depreciation and utility plant. The Company could not replace its non-nuclear utility plant and equipment for the historical cost value at which they are recorded on the Company's books. In addition, the Company would not replace these with identical assets due to technological advances and competitive and regulatory changes that have occurred. In light of these considerations, the depreciation charges in operating expenses do not reflect the cost of providing service if new generating facilities were installed. The Company will seek additional revenue or reallocate resources, if possible, to cover the costs of maintaining service as assets are replaced or retired.

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

FINANCIAL POSITION. The Company's capital structure at December 31, 1997 was 51.8% long-term debt, 7.7% preferred stock and 40.5% common equity, as compared to 53.1%, 7.9% and 39.0% respectively, at December 31, 1996. The culmination of the termination, restatement or amendment of IPP contracts will significantly increase the leverage of the Company to nearly 65% at the time of closing. Through the anticipated increased operating cash flow resulting from the MRA and PowerChoice agreement, the planned rapid repayment of debt should deleverage the Company over time. Book value of the common stock was $18.89 per share at December 31, 1997, as compared to $17.91 per share at December 31, 1996. With the issuance of equity at below book value to the IPP Parties as part of the MRA, book value per share will be diluted. In addition, earnings per share will be diluted by the effect of the issuance to the IPP Parties of approximately 42.9 million shares of the Company's common stock.

The Company's EBITDA for 1997 was approximately $962 million, and upon implementation of the MRA and PowerChoice is expected to increase to approximately $1,200 million to $1,300 million per year. EBITDA represents earnings before interest charges, interest income, income taxes, depreciation and amortization, amortization of nuclear fuel, allowance for funds used during construction, non-cash regulatory deferrals and other amortizations and extraordinary items. EBITDA is a non-GAAP measure of cash flows and is presented to provide additional information about the Company's ability to meet its future requirements for debt service which would increase significantly upon consummation of the MRA. EBITDA should not be considered an alternative to net income as an indicator of operating performance or as an alternative to cash flows, as presented on the Consolidated Statement of Cash Flows, as a measure of liquidity.

The 1997 ratio of earnings to fixed charges was 2.02 times. The ratios of earnings to fixed charges for 1996 and 1995 were 1.57 times and 2.29 times, respectively. The change in the ratio was primarily due to changes in earnings during the period. Assuming the MRA is implemented, the ratio of earnings to fixed charges will substantially decrease in the future, since the MRA and PowerChoice agreement will have the effect of substantially depressing earnings during its five-year term, while at the same time substantially improving operating cash flows. The primary objective of the MRA is to convert a large and growing off-balance sheet payment obligation that threatens the financial viability of the Company into a fixed and manageable capital obligation.

COMMON STOCK DIVIDEND. The Board of Directors omitted the common stock dividend beginning the first quarter of 1996. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addresses growing pressure from mandated power purchases and weaker sales and is the primary reason for the increase in the cash balance. In making future dividend decisions, the Board of Directors will evaluate, along with standard business considerations, the financial condition of the Company, the closing of the MRA and implementation of PowerChoice, or the failure to implement such actions, contractual restrictions that might be entered into in conjunction with financing the MRA, the degree of competitive pressure on its prices, the level of available cash flow and retained earnings and other strategic considerations. The Company expects to dedicate a substantial portion of its future expected positive cash flow to reduce the leverage created in connection with the implementation of the MRA. The PowerChoice agreement establishes limits to the annual amount of common and preferred stock dividends that can be paid by the regulated business. The limit is based upon the amount of net income each year, plus a specified amount ranging from $50 million in 1998 to $100 million in 2000. The dividend limitation is subject to review after the term of the PowerChoice agreement. Furthermore, the Company forecasts that earnings for the five-year term of the PowerChoice agreement will be substantially depressed, as non-cash amortization of the MRA regulatory asset is occurring and the interest costs on the IPP debt is the greatest. See "Accounting Implications of the PowerChoice Agreement and Master Restructuring Agreement."

CONSTRUCTION AND OTHER CAPITAL REQUIREMENTS. The Company's total capital requirements consist of amounts for the Company's construction program (see Item 8. Financial Statements and Supplementary Data - "Note 9. Commitments and Contingencies - Construction Program,"). The January 1998 ice storm damage restoration costs may further add to these requirements (see Item 8. Financial Statements and Supplementary Data - "Note 13. Subsequent Event"), nuclear decommissioning funding requirements (See Item 8. Financial Statements and Supplementary Data - "Note 3. Nuclear Operations - Nuclear Plant Decommissioning" and - "NRC Policy Statement and Proposal"), working capital needs, maturing debt issues and sinking fund provisions on preferred stock, as well as requirements to complete the MRA and accomplish the restructuring contemplated by the PowerChoice agreement. Annual expenditures for the years 1995 to 1997 for construction and nuclear fuel, including related AFC and overheads capitalized, were $345.8 million, $352.1 million and $290.8 million, respectively, and are budgeted to be approximately $358 million for 1998 and to range from $279 - $352 million for each of the subsequent four years. These estimates include construction expenditures for non- nuclear generation of $20 million to $38 million per year.

In addition to the assumed cost of the MRA requirements, as described below, mandatory debt and preferred stock retirements are expected to add approximately another $77 million to the 1998 estimate of capital requirements. The estimate of construction additions included in capital requirements for the period 1998 to 2002 will be reviewed by management to give effect to the storm restoration costs and the overall objective of further reducing construction spending where possible. See discussion in "Liquidity and Capital Resources" section below, which describes how management intends to meet its financing needs for this five-year period.

Under the MRA, the Company will pay an aggregate of $3,616 million in cash. The Company expects to issue senior unsecured debt to fund this requirement, which is expected to consist of both debt issued through a public market offering and debt issues to banks which would serve to replace its existing $804 million senior debt facility, discussed below. The Company's preferred shareholders gave the Company approval to increase the amount of unsecured debt the Company may issue by $5 billion. Previously, the Company was able to issue $700 million under the restrictions of its amended Certificate of Incorporation. This authorization will enable the issuance of unsecured debt to consummate the MRA. In addition, the Company believes that the ability to use unsecured indebtedness will increase its flexibility in planning and financing its business activities.

LIQUIDITY AND CAPITAL RESOURCES. External financing plans are subject to periodic revision as underlying assumptions are changed to reflect developments, market conditions and, most importantly, conclusion of the MRA and implementation of PowerChoice. The ultimate level of financing during the period 1998 through 2002 will be affected by, among other things: the timing and outcome of the MRA and the cash tax benefits anticipated because the MRA is expected to result in a net operating loss for 1998 income tax purposes; the implementation of the PowerChoice agreement, levels of common dividend payments, if any, and preferred dividend payments; the results of the auction of the Company's fossil and hydro assets; the Company's competitive position and the extent to which competition penetrates the Company's markets; uncertain energy demand due to the weather and economic conditions; and the effects of the ice storm that struck a portion of the Company's service territory in early 1998. The proceeds of the sale of the fossil and hydro assets will be subject to the terms of the Company's mortgage indenture and the note indenture that will be entered into in connection with the MRA debt financing. The Company could also be affected by the outcome of the NRC's consideration of new rules for adequate financial assurance of nuclear decommissioning obligations. (See Item 8. Notes to Consolidated Financial Statements - "Note 3. Nuclear Operations - NRC Policy Statement and Proposal" and "Note 13. Subsequent Event").

The Company has an $804 million senior debt facility with a bank group, consisting of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA. The interest rate applicable to the senior debt facility is variable based on certain rate options available under the agreement and currently approximates 7.7% (but is capped at 15%). As of December 31, 1997, the amount outstanding under the senior debt facility was $529 million, consisting of $105 million under the term loan facility and a $424 million letter of credit, leaving the Company with $275 million of borrowing capability under the facility. The facility expires on June 30, 1999 (subject to earlier termination if the Company separates its fossil/hydro generation business from its transmission and distribution business, or any other significant restructuring plan). The Company is currently negotiating with the lenders to replace the senior debt facility with a larger facility to finance a portion of the MRA.

This facility is collateralized by first mortgage bonds which were issued on the basis of additional property under the earnings test required under the mortgage trust indenture ("First Mortgage Bonds"). As of December 31, 1997, the Company could issue an additional $1,396 million aggregate principal amount of First Mortgage Bonds under the Company's mortgage trust indenture. This amount is based upon retired bonds without regard to an interest coverage test. The Company is presently precluded from issuing First Mortgage Bonds based on additional property.

Although no assurance can be provided, the Company believes that the closing of the MRA and implementation of PowerChoice will result in substantially depressed earnings during its five-year term, but will substantially improve operating cash flows. There is risk throughout the electric industry that credit ratings could decline if the issue of stranded cost recovery is not satisfactorily resolved. In the event the MRA is not closed, and comparable solutions are not available, the Company will undertake other actions necessary to act in the best interests of stockholders and other constituencies.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a periodic basis. This approach generally results in the Company showing a working capital deficit. This has not been the case in the last two years as the Company's cash balance has increased, reflecting suspension of the common stock dividend in 1996. Working capital deficits may also be a result of the seasonal nature of the Company's operations as well as timing differences between the collection of customer receivables and the payment of fuel and purchased power costs. The Company believes it has sufficient borrowing capacity to fund deficits as necessary in the near term. However, the Company's borrowing capacity to fund such deficits may be affected by the factors discussed above relating to the Company's external financial plans.

Since 1995, past-due accounts receivable have increased significantly. A number of factors have contributed to the increase, including rising prices (particularly to residential customers). Rising prices have been driven by increased payments to IPPs and high taxes and have been passed on in customers' bills. The stagnant economy in the Company's service territory since the early 1990's has adversely affected collection of past-due accounts. Also, laws, regulations and regulatory policies impose more stringent collection limitations on the Company than those imposed on business in general; for example, the Company faces more stringent requirements to terminate service during the winter heating season. The increase in the allowance for doubtful accounts was attributable to the reassessment of the collection risk associated with residential accounts receivable and arrears. The Company has implemented a number of collection initiatives that are expected to result in lower arrears levels and potentially lower the allowance for doubtful accounts. The Company has and will continue to implement a variety of strategies to improve its collection of past due accounts and reduce its bad debt expense.

The information gathered in developing these strategies enabled management to update its risk assessment of the accounts receivable portfolio. Based on this assessment, management determined that the level of risk associated primarily with the older accounts had increased and the historical loss experience no longer applied. Accordingly, the Company determined that a significant portion of the past-due accounts receivable (principally of residential customers) might be uncollectible, and had written-off a substantial number of these accounts as well as increased its allowance for doubtful accounts in 1996. In 1997 and 1996, the Company charged $46.5 million and $127.6 million, respectively to bad debt expense. The allowance for doubtful accounts is based on assumptions and judgments as to the effectiveness of collection efforts. Future results with respect to collecting the past-due receivables may prove to be different from those anticipated. Although the Company has experienced a level of improvement in collection efforts, future results are necessarily dependent upon the following factors, including, among other things, the effectiveness of the strategies discussed above, the support of regulators and legislators to allow utilities to move towards commercial collection practices and improvement in the condition of the economy in the Company's service territory. The Company has been pursuing PowerChoice to address high prices that are the result of traditional price regulation, but the introduction of competition requires that policies and practices that were central to traditional regulation, including those involving collections, be changed so as not to jeopardize the benefits of competition.

NET CASH PROVIDED BY OPERATING ACTIVITIES decreased $162.8 million in 1997 primarily due to a decrease of $105.9 million in the amount of accounts receivable sold under the accounts receivable sales program (which the Company has budgeted to restore in 1998) partially offset by an increase in deferred taxes of $53.9 million.

NET CASH USED IN INVESTING ACTIVITIES increased $62.4 million in 1997 primarily as a result of an increase in other cash investments of $116.1 million offset by a decrease in the acquisition of utility plant of $62.9 million.

NET CASH USED IN FINANCING ACTIVITIES decreased $106.1 million, primarily due to a net reduction of $94.7 million in the payments on long-term debt.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. FINANCIAL STATEMENTS

Report of Management
Report of Independent Accountants
Consolidated Statements of Income and Retained Earnings for each of the three years in the period ended December 31, 1997.
Consolidated Balance Sheets at December 31, 1997 and 1996.
Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 1997.
Notes to Consolidated Financial Statements.

REPORT OF MANAGEMENT

The consolidated financial statements of the Company and its subsidiaries were prepared by and are the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records and protection of assets. This system includes communication through written policies and procedures, an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program. In addition, the Company has a Corporate Policy Register and a Code of Business Conduct (the "Code") that supply employees with a framework describing and defining the Company's overall approach to business and require all employees to maintain the highest level of ethical standards as well as requiring all management employees to formally affirm their compliance with the Code.

The financial statements have been audited by Price Waterhouse LLP, the Company's independent accountants, in accordance with GAAP. In planning and performing its audit, Price Waterhouse LLP considered the Company's internal control structure in order to determine auditing procedures for the purpose of expressing an opinion on the financial statements, and not to provide assurance on the internal control structure. The independent accountants' audit does not limit in any way management's responsibility for the fair presentation of the financial statements and all other information, whether audited or unaudited, in this Annual Report. The Audit Committee of the Board of Directors, consisting of five outside directors who are not employees, meets regularly with management, internal auditors and Price Waterhouse LLP to review and discuss internal accounting controls, audit examinations and financial reporting matters. Price Waterhouse LLP and the Company's internal auditors have free access to meet individually with the Audit Committee at any time. without management being present.

/s/ William E. Davis
William E. Davis
Chairman of the Board and
Chief Executive Officer
Niagara Mohawk Power Corporation

REPORT OF INDEPENDENT ACCOUNTANTS

To the Stockholders and
Board of Directors of
Niagara Mohawk Power Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and retained earnings and of cash flows present fairly, in all material respects, the financial position of Niagara Mohawk Power Corporation and its subsidiaries at December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in Note 15 to the accompanying financial statements, the Company has restated its 1997 financial statements to eliminate the $190 million charge related to the limitation on the recoverability of the regulatory asset described in Note 2.

As discussed in Note 2, the Company believes that it continues to meet the requirements for application of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71) for its nuclear generation, electric transmission and distribution and gas businesses. In the event that the Company is unable to complete the termination, restatement or amendment of the independent power producer contracts, this conclusion could change in 1998 and beyond, resulting in material adverse effects on the Company's financial condition and results of operations.

As discussed in Note 2, the Company discontinued application of SFAS No. 71 for its non-nuclear generation business in 1996.

Price Waterhouse LLP
PRICE WATERHOUSE LLP

Syracuse, New York
March 26, 1998, except Note 2 (third paragraph)
and Note 15, as to which the date is May 29, 1998

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS

For the year ended December 31,	1997	1996	1995
	In thousands of dollars		
Operating revenues:			
Electric	$3,309,441	$3,308,979	$3,335,548
Gas	656,963	681,674	581,790
	3,966,404	3,990,653	3,917,338
Operating expenses:			
Fuel for electric generation	179,455	181,486	165,929
Electricity purchased	1,236,108	1,182,892	1,137,937
Gas purchased	345,610	370,040	276,232
Other operation and maintenance expenses	835,282	928,224	817,897
Depreciation and amortization (Note 1)	339,641	329,827	317,831
Other taxes	471,469	475,846	517,478
	3,407,565	3,468,315	3,233,304
Operating income	558,839	522,338	684,034
Other income (Note 1)	24,997	35,943	3,069
Income before interest charges	583,836	558,281	687,103
Interest charges (Note 1)	273,906	278,033	279,674
Income before federal and foreign income taxes	309,930	280,248	407,429
Federal and foreign income taxes (Note 7)	126,595	102,494	159,393
Income before extraordinary item	183,335	177,754	248,036
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes of $36,273 in 1996 (Note 2)	-	(67,364)	-
Net income (Note 15)	183,335	110,390	248,036
Dividends on preferred stock	37,397	38,281	39,596
Balance available for common stock	145,938	72,109	208,440
Dividends on common stock	-	-	161,650
	145,938	72,109	46,790

Retained earnings at beginning of year	657,482	585,373	538,583
Retained earnings at end of year	$ 803,420	$ 657,482	$ 585,373
Average number of shares of common stock outstanding (in thousands)	144,404	144,350	144,329
Basic and diluted earnings per average share of common stock before extraordinary item	$ 1.01	$ 0.97	$ 1.44
Extraordinary item	$ -	$ (0.47)	$ -
Basic and diluted earnings per average share of common stock	$ 1.01	$ 0.50	$ 1.44
Dividends on common stock paid per share	$ -	$ -	$ 1.12

() Denotes deduction

The accompanying notes are an integral part of these financial statements

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

In thousands of dollars		
At December 31,	1997	1996
ASSETS		
Utility plant (Note 1):		
Electric plant	$ 8,752,865	$ 8,611,419
Nuclear Fuel	577,409	573,041
Gas plant	1,131,541	1,082,298
Common plant	319,409	292,591
Construction work in progress	294,650	279,992
Total utility plant	11,075,874	10,839,341
Less: Accumulated depreciation and amortization	4,207,830	3,881,726
Net utility plant	6,868,044	6,957,615
Other property and investments	371,709	257,145
Current assets:		
Cash, including temporary cash investments of $315,708 and $223,829, respectively	378,232	325,398
Accounts receivable (less allowance for doubtful accounts of $62,500 and $52,100, respectively) (Notes 1 and 9)	492,244	373,305
Materials and supplies, at average cost:		
Coal and oil for production of electricity	27,642	20,788
Gas storage	39,447	43,431
Other	118,308	120,914
Prepaid taxes	15,518	11,976
Other	20,309	25,329
	1,091,700	921,141
Regulatory assets (Note 2):		
Regulatory tax asset	399,119	416,599
Deferred finance charges	239,880	239,880
Deferred environmental restoration costs (Note 9)	220,000	225,000
Unamortized debt expense	57,312	65,993
Postretirement benefits other than pensions	56,464	60,482

Other	204,049	206,352
	1,176,824	1,214,306
Other assets	75,864	77,428
	$9,584,141	$9,427,635

The accompanying notes are an integral part of these financial statements

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

	In thousands of dollars	
At December 31,	1997	1996
CAPITALIZATION AND LIABILITIES		
Capitalization (Note 5):		
Common stockholders' equity: Common stock, issued 144,419,351 and 144,365,214 shares, respectively	$ 144,419	$ 144,365
Capital stock premium and expense	1,779,688	1,783,725
Retained earnings	803,420	657,482
	2,727,527	2,585,572
Non-redeemable preferred stock	440,000	440,000
Mandatorily redeemable preferred stock	76,610	86,730
Long-term debt	3,417,381	3,477,879
Total capitalization	6,661,518	6,590,181
Current liabilities:		
Long-term debt due within one year (Note 5)	67,095	48,084
Sinking fund requirements on redeemable preferred stock (Note 5)	10,120	8,870
Accounts payable	263,095	271,830
Payable on outstanding bank checks	23,720	32,008
Customers' deposits	18,372	15,505
Accrued taxes	9,005	4,216
Accrued interest	62,643	63,252
Accrued vacation pay	36,532	36,436
Other	64,756	52,455
	555,338	532,656
Regulatory liabilities (Note 2):		
Deferred finance charges	239,880	239,880
Other liabilities:		
Accumulated deferred income taxes (Notes 1 and 7)	1,387,032	1,357,518

Employee pension and other benefits (Note 8)	240,211	238,688
Deferred pension settlement gain	12,438	19,269
Unbilled revenues (Note 1)	43,281	49,881
Other	224,443	174,562
	1,907,405	1,839,918
Commitments and contingencies (Notes 2 and 9):		
Liability for environmental restoration	220,000	225,000
	$9,584,141	$9,427,635

The accompanying notes are an integral part of these financial statements

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

INCREASE (DECREASE) IN CASH

In thousands of dollars

For the year ended December 31,	1997	1996	1995
Cash flows from operating activities:			
Net income	$ 183,335	$ 110,390	$ 248,036
Adjustments to reconcile net income to net cash provided by operating activities:			
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes	-	67,364	-
Depreciation and amortization	339,641	329,827	317,831
Electric margin recoverable	-	-	58,588
Amortization of nuclear fuel	25,241	38,077	34,295
Provision for deferred income taxes	46,994	(6,870)	114,917
Gain on sale of subsidiary	-	(15,025)	(11,257)
Unbilled revenues	(6,600)	21,471	(71,258)
Net accounts receivable	(118,939)	121,198	56,748
Materials and supplies	(1,306)	2,265	13,663
Accounts payable and accrued expenses	(11,175)	8,224	(47,048)
Accrued interest and taxes	4,180	(11,750)	(35,440)
Changes in other assets and liabilities	76,204	35,231	20,930
Net cash provided by operating activities	537,575	700,402	700,005
Cash flows from investing activities:			
Construction additions	(286,389)	(296,689)	(332,443)
Nuclear fuel	(4,368)	(55,360)	(13,361)
Less: Allowance for other funds used during construction	5,310	3,665	1,063
Acquisition of utility plant	(285,447)	(348,384)	(344,741)
Decrease in materials and Materials and supplies related ton construction	1,042	8,362	3,346
Accounts payable and accrued expenses related to construction	(2,794)	2,056	(7,112)
Other investments	(115,533)	541	(115,818)
Proceeds from sale of subsidiary (net of cash sold)	-	14,600	161,087
Other	8,761	(8,786)	26,234
Net cash used in investing activities	(393,971)	(331,611)	(277,004)
Cash flows from financing activities:			
Proceeds from long-term debt	-	105,000	346,000
Redemption of preferred stock	(8,870)	(10,400)	(10,950)
Reductions of long-term debt	(44,600)	(244,341)	(73,415)
Net change in short-term debt	-	-	(416,750)
Dividends paid	(37,397)	(38,281)	(201,246)
Other	97	(8,846)	(7,495)

Net cash used in financing activities	(90,770)	(196,868)	(363,856)
Net increase in cash	52,834	171,923	59,145
Cash at beginning of year	325,398	153,475	94,330
Cash at end of year	$ 378,232	$ 325,398	$ 153,475

Supplemental disclosures of cash flow information:

Cash paid during the year for:

Interest	$ 279,957	$ 286,497	$ 290,352
Income taxes	$ 82,331	$ 95,632	$ 47,378

The accompanying notes are an integral part of these financial statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Company is subject to regulation by the PSC and FERC with respect to its rates for service under a methodology which establishes prices based on the Company's cost. The Company's accounting policies conform to GAAP, including the accounting principles for rate-regulated entities with respect to the Company's nuclear, transmission, distribution and gas operations (regulated business), and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The Company discontinued the application of regulatory accounting principles to its fossil and hydro generation operations in 1996 (see Note 2). In order to be in conformity with GAAP, management is required to use estimates in the preparation of the Company's financial statements.

PRINCIPLES OF CONSOLIDATION: The consolidated financial statements include the Company and its wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated.

UTILITY PLANT: The cost of additions to utility plant and replacements of retirement units of property are capitalized. Cost includes direct material, labor, overhead and AFC. Replacement of minor items of utility plant and the cost of current repairs and maintenance is charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. The discontinuation of SFAS No. 71 did not affect the carrying value of the Company's utility plant.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION: The Company capitalizes AFC in amounts equivalent to the cost of funds devoted to plant under construction for its regulated business. AFC rates are determined in accordance with FERC and PSC regulations. The AFC rate in effect during 1997 was 9.28%. AFC is segregated into its two components, borrowed funds and other funds, and is reflected in the "Interest charges" and the "Other income" sections, respectively, of the Consolidated Statements of Income. The amount of AFC credits recorded in each of the three years ended December 31, in thousands of dollars, was as follows:

	1997	1996	1995
Other income	$5,310	$3,665	$1,063
Interest charges	4,396	3,690	7,987

As a result of the discontinued application of SFAS No. 71 to the fossil and hydro operations, the Company capitalizes interest cost associated with the construction of fossil/hydro assets.

DEPRECIATION, AMORTIZATION AND NUCLEAR GENERATING PLANT DECOMMISSIONING COSTS: For accounting and regulatory purposes, depreciation is computed on the straight-line basis using the license lives for nuclear and hydro classes of depreciable property and the average service lives for all other classes. The percentage relationship between the total provision for depreciation and average depreciable property was approximately 3% for the years 1995 through 1997. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation rates when necessary.

Estimated decommissioning costs (costs to remove a nuclear plant from service in the future) for the Company's Unit 1 and its share of Unit 2 are being accrued over the service lives of the units, recovered in rates through an annual allowance and currently charged to operations through depreciation. The Company expects to commence decommissioning of both units shortly after cessation of operations at Unit 2 (currently planned for 2026), using a method which removes or decontaminates the Units components promptly at that time. See Note 3 - "Nuclear Plant Decommissioning."

The FASB issued an exposure draft in February 1996 entitled "Accounting for Certain Liabilities Related to Closure or Removal Costs of Long-Lived Assets." The scope of the project includes certain plant decommissioning costs, including those for fossil, hydro and nuclear plants. If approved, a liability would be recognized, with a corresponding plant asset, whenever a legal or constructive obligation exists to perform dismantlement or removal activities. The Company currently recognizes the liability for nuclear decommissioning over the service life of the plant as an increase to accumulated depreciation and does not recognize the closure or removal obligation associated with its fossil and hydro plants. The Company's PowerChoice agreement provides for the recovery of nuclear decommissioning costs. As discussed in Note 2, the Company intends to sell its fossil and hydro generating assets through an auction process. To the extent the assets are sold, the effect of this exposure draft on the Company should be mitigated. However, the Company cannot predict the results of the auction. The adoption of the proposed standard is not expected to impact the cash flow from these assets. The FASB continues to discuss the issues addressed in the exposure draft, as well as the timing of its implementation.

Amortization of the cost of nuclear fuel is determined on the basis of the quantity of heat produced for the generation of electric energy. The cost of disposal of nuclear fuel, which presently is $.001 per KWh of net generation available for sale, is based upon a contract with the DOE. These costs are charged to operating expense and recovered from customers through base rates or through the fuel adjustment clause.

REVENUES: Revenues are based on cycle billings rendered to certain customers monthly and others bi-monthly for energy consumed and not billed at the end of the fiscal year. At December 31, 1997 and 1996, approximately $8.6 million and $11.1 million, respectively, of unbilled electric revenues remained unrecognized in results of operations, are included in "Other liabilities." Under the Company's PowerChoice agreement, the amount of unrecognized electric unbilled revenue as of the PowerChoice implementation date will be netted against certain other regulatory assets and liabilities. Thereafter, changes in electric unbilled revenues will no longer be deferred. In 1995, the Company used $71.5 million of electric unbilled revenues to reduce the 1995 revenue requirement. At December 31, 1997 and 1996, $34.7 million and $38.8 million, respectively, of unbilled gas revenues remain unrecognized in results of operations and may be used to reduce future gas revenue requirements. The unbilled revenues included in accounts receivable at December 31, 1997 and 1996, were $211.9 million and $218.5 million, respectively.

The Company's tariffs include electric and gas adjustment clauses under which energy and purchased gas costs, respectively, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company, as authorized by the PSC, charges operations for energy and purchased gas cost increases in the period of recovery. The PSC has periodically authorized the Company to make changes in the level of allowed energy and purchased gas costs included in approved rate schedules. As a result of such periodic changes, a portion of energy costs deferred at the time of change would not be recovered or may be overrecovered under the normal operation of the electric and gas adjustment clauses. However, the Company has to date been permitted to defer and bill or credit such portions to customers, through the electric and gas adjustment clauses, over a specified period of time from the effective date of each change.

The Company's electric FAC provides for partial pass-through of fuel and purchased power cost fluctuations from amounts forecast, with the Company absorbing a portion of increases or retaining a portion of decreases up to a maximum of $15 million per rate year. Thereafter, 100% of the fluctuation is passed on to ratepayers. The Company also shares with ratepayers fluctuations from amounts forecast for net resale margin and transmission benefits, with the Company retaining/absorbing 40% and passing 60% through to ratepayers. The amounts retained or absorbed in 1995 through 1997 were not material. Under the PowerChoice agreement, the FAC will be discontinued.

In December 1996, the Company, Multiple Intervenors and the PSC staff reached a three year gas settlement that was conditionally approved by the PSC. The agreement eliminated the gas adjustment clause and established a gas commodity cost adjustment clause ("CCAC"). The Company's gas CCAC provides for the collection or passback of certain increases or decreases from the base commodity cost of gas. The maximum annual risk or benefit to the Company is $2.25 million. All savings and excess costs beyond that amount will flow to ratepayers. For a discussion of the ratemaking associated with non-commodity gas costs, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Other Federal and State Regulatory Initiatives - Multi-Year Gas Rate Settlement Agreement."

FEDERAL INCOME TAXES: As directed by the PSC, the Company defers any amounts payable pursuant to the alternative minimum tax rules. Deferred investment tax credits are amortized over the useful life of the underlying property.

STATEMENT OF CASH FLOWS: The Company considers all highly liquid investments, purchased with a remaining maturity of three months or less, to be cash equivalents.

EARNINGS PER SHARE: Basic earnings per share ("EPS") is computed based on the weighted average number of common shares outstanding for the period. The number of options outstanding at December 31, 1997, 1996 and 1995 that could potentially dilute basic EPS, (but are considered antidilutive for each period because the options exercise price was greater than the average market price of common shares), is immaterial. Therefore, the calculation of both basic and dilutive EPS are the same for each period.

RECLASSIFICATIONS: Certain amounts from prior years have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1997 presentation.

COMPREHENSIVE INCOME: In June 1997, FASB issued SFAS No. 130. SFAS No. 130 establishes standards for reporting comprehensive income. Comprehensive income is the change in the equity of a company, not including those changes that result from shareholder transactions. All components of comprehensive income are required to be reported in a new financial statement that is displayed with equal prominence as existing financial statements. The Company will be required to adopt SFAS No. 130 on January 1, 1998. The Company does not expect that adoption of SFAS No. 130 will have a significant impact on its reporting and disclosure requirements.

SEGMENT DISCLOSURES: Also in June 1997, FASB issued SFAS No. 131. SFAS No. 131 establishes standards for additional disclosure about operating segments for interim and annual financial statements. More specifically, it requires financial information to be disclosed for segments whose operating results are reviewed by the chief operating officer for decisions on resource allocation. It also requires related disclosures about product and services, geographic areas and major customers. The Company will be required to adopt SFAS No. 131 for the fiscal year ending December 31, 1998. The Company does not expect that the adoption of SFAS No. 131 will have a significant impact on its reporting and disclosure requirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS: In February 1998, FASB issued SFAS No. 132. SFAS No. 132 revises employers' disclosures about pension and other postretirement benefit plans. It does not change the measurement or recognition of those plans. It standardizes the disclosure requirements for pensions and other postretirement benefits to the extent practicable and requires additional information on changes in the benefit obligations and fair values of plan assets. The Company will be required to adopt SFAS No. 132 for the fiscal year ending December 31, 1998. The Company does not expect the adoption of SFAS No. 132 will have a significant impact on its reporting and disclosure requirements.

NOTE 2. RATE AND REGULATORY ISSUES AND CONTINGENCIES

The Company's financial statements conform to GAAP, including the accounting principles for rate-regulated entities with respect to its regulated operations. Substantively, these principles permit a public utility, regulated on a cost-of-service basis, to defer certain costs which would otherwise be charged to expense, when authorized to do so by the regulator. These deferred costs are known as regulatory assets, which in the case of the Company are approximately $937 million, net of approximately $240 million of regulatory liabilities at December 31, 1997. These regulatory assets are probable of recovery. The portion of the $937 million which has been allocated to the nuclear generation and electric transmission and distribution business is approximately $810 million, which is net of approximately $240 million of regulatory liabilities. Regulatory assets allocated to the rate-regulated gas distribution business are $127 million. Generally, regulatory assets and liabilities were allocated to the portion of the business that incurred the underlying transaction that resulted in the recognition of the regulatory asset or liability. The allocation methods used between electric and gas are consistent with those used in prior regulatory proceedings.

The Company concluded as of December 31, 1996 that the termination, restatement or amendment of IPP contracts and implementation of PowerChoice was the probable outcome of negotiations that had taken place since the PowerChoice announcement. Under PowerChoice, the separated non-nuclear generation business would no longer be rate-regulated on a cost-of-service basis and, accordingly, regulatory assets related to the non-nuclear power generation business, amounting to approximately $103.6 million ($67.4 million after tax or 47 cents per share) was charged against 1996 income as an extraordinary non-cash charge.

The PSC in its written order issued March 20, 1998 approving PowerChoice, determined to limit the estimated value of the MRA regulatory asset that can be recovered from customers to approximately $4,000 million. The ultimate amount of the regulatory asset to be established may vary based on certain events related to the closing of the MRA. The estimated value of the MRA regulatory asset includes the issuance of 42.9 million shares of common stock, which the PSC in determining the recoverable amount of such asset, valued at $8 per share. Because the value of the consideration to be paid to the IPP Parties can only be determined at the MRA closing, the value of the limitation on the recoverability of the MRA regulatory asset is expected to be recorded as a charge to expense in the second quarter of 1998 upon the closing of the MRA. The charge to expense will be determined as the difference between S8 per share and the Company's closing common stock price on the date the MRA closes, multiplied by 42.9 million shares. Using the Company's common stock price on March 26, 1998 of $12 7/16 per share, the charge to expense would be approximately $190 million (85 cents per share).

Under PowerChoice, the Company's remaining electric business (nuclear generation and electric transmission and distribution business) will continue to be rate-regulated on a cost-of-service basis and, accordingly, the Company continues to apply SFAS No. 71 to these businesses. Also, the Company's IPP contracts, including those restructured under the MRA and those not so restructured will continue to be the obligations of the regulated business.

The EITF of the FASB reached a consensus on Issue No. 97-4 "Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101" in July 1997. As discussed previously, the Company discontinued the application of SFAS No. 71 and applied SFAS No. 101 with respect to the fossil and hydro generation business at December 31, 1996, in a manner consistent with the EITF consensus.

In addition, EITF 97-4 does not require the Company to earn a return on regulatory assets that arise from a deregulating transition plan in assessing the applicability of SFAS No. 71. In the event the MRA and PowerChoice are implemented, the Company believes that the regulated cash flows to be derived from prices it will charge for electric service over 10 years, including the CTC, assuming no unforeseen reduction in demand or bypass of the CTC or exit fees, will be sufficient to recover the MRA regulatory asset and to provide recovery of and a return on the remainder of its assets, as appropriate. In the event the Company could no longer apply SFAS No. 71 in the future, it would be required to record an after-tax non-cash charge against income for any remaining unamortized regulatory assets and liabilities. Depending on when SFAS No. 71 was required to be discontinued, such charge would likely be material to the Company's reported financial condition and results of operations and the Company's ability to pay dividends.

The PowerChoice agreement, while having the effect of substantially depressing earnings during its five-year term, will substantially improve operating cash flows.

With the implementation of PowerChoice, specifically the separation of non-nuclear generation as an entity that would no longer be cost-of-service regulated, the Company is required to assess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. SFAS No. 121 requires long-lived assets and certain identifiable intangibles held and used by an entity to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable or when assets are to be disposed of. In performing the review for recoverability, the Company is required to estimate future undiscounted cash flows expected to result from the use of the asset and/or its disposition. The Company has determined that there is no impairment of its fossil and hydro generating assets. To the extent the proceeds resulting from the sale of the fossil and hydro assets are not sufficient to avoid a loss, the Company would be able to recover such loss through the CTC. The PowerChoice agreement provides for deferral and future recovery of losses, if any, resulting from the sale of the non-nuclear generating assets. The Company believes that it will be permitted to record a regulatory asset for any such loss in accordance with EITF 97-4. The Company's fossil and hydro generation plant assets had a net book value of approximately $1.1 billion at December 31, 1997.

As described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement," the conclusion of the termination, restatement or amendment of IPP contracts, and closing of the financing necessary to implement such termination, restatement or amendment, as well as implementation of PowerChoice, is subject to a number of contingencies. In the event the Company is unable to successfully bring these events to conclusion, it is likely that application of SFAS No. 71 would be discontinued. The resulting non-cash after-tax charges against income, based on regulatory assets and liabilities associated with the nuclear generation and electric transmission and distribution businesses as of December 31, 1997, would be approximately $526.5 million or $3.65 per share. Various requirements under applicable law and regulations and under corporate instruments, including those with respect to issuance of debt and equity securities, payment of common and preferred dividends and certain types of transfers of assets could be adversely impacted by any such write- downs.

The Company has recorded the following regulatory assets on its Consolidated Balance Sheets reflecting the rate actions of its regulators:

REGULATORY TAX ASSET represents the expected future recovery from ratepayers of the tax consequences of temporary differences between the recorded book bases and the tax bases of assets and liabilities. This amount is primarily timing differences related to depreciation. These amounts are amortized and recovered as the related temporary differences reverse. In January 1993, the PSC issued a Statement of Interim Policy on Accounting and Ratemaking Procedures that required adoption of SFAS No. 109 on a revenue- neutral basis.

DEFERRED FINANCE CHARGES represent the deferral of the discontinued portion of AFC related to CWIP at Unit 2 which was included in rate base. In 1985, pursuant to PSC authorization, the Company discontinued accruing AFC on CWIP for which a cash return was being allowed. This amount, which was accumulated in deferred debit and credit accounts up to the commercial operation date of Unit 2, awaits future disposition by the PSC. A portion of the deferred credit could be utilized to reduce future revenue requirements over a period shorter than the life of Unit 2, with a like amount of deferred debit amortized and recovered in rates over the remaining life of Unit 2. PowerChoice provides for netting, and thereby elimination of the debit and credit balances of deferred finance charges.

DEFERRED ENVIRONMENTAL RESTORATION COSTS represent the Company's share of the estimated costs to investigate and perform certain remediation activities at both Company-owned sites and non- owned sites with which it may be associated. The Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. PowerChoice and the Company's gas settlement provide for the recovery of these costs over the settlement periods. The Company believes future costs, beyond the settlement periods, will continue to be recovered in rates. See Note 9 - "Environmental Contingencies."

UNAMORTIZED DEBT EXPENSE represents the costs to issue and redeem certain long-term debt securities which were retired prior to maturity. These amounts are amortized as interest expense ratably over the lives of the related issues in accordance with PSC directives.

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS represent the excess of such costs recognized in accordance with SFAS No. 106 over the amount received in rates. In accordance with the PSC policy statement, postretirement benefit costs other than pensions are being phased-in to rates over a five-year period and amounts deferred will be amortized and recovered over a period not to exceed 20 years.

Substantially all of the Company's regulatory assets described above are being amortized to expense and recovered in rates over periods approved in the Company's electric and gas rate cases, respectively.

NOTE 3. NUCLEAR OPERATIONS

NUCLEAR PLANT DECOMMISSIONING: The Company's site specific cost estimates for decommissioning Unit 1 and its ownership interest in Unit 2 at December 31, 1997 are as follows:

	Unit 1	Unit 2
Site Study (year)	1995	1995
End of Plant Life (year)	2009	2026
Radioactive Dismantlement to Begin (year)	2026	2028
Method of Decommissioning	Delayed Dismantlement	Immediate Dismantlement
Cost of Decommissioning (in January 1998 dollars)	In millions of dollars	
Radioactive Components	$481	$201
Non-radioactive Components	117	48
Fuel Dry Storage/Continuing Care	78	43
	$676	$292

The Company estimates that by the time decommissioning is completed, the above costs will ultimately amount to $1.7 billion and $.9 billion for Unit 1 and Unit 2, respectively, using approximately 3.5% as an annual inflation factor.

In addition to the costs mentioned above, the Company expects to incur post-shutdown costs for plant rampdown, insurance and property taxes. In 1998 dollars, these costs are expected to amount to $119 million and $63 million for Unit 1 and the Company's share of Unit 2, respectively. The amounts will escalate to $210 million and $190 million for Unit 1 and the Company's share of Unit 2, respectively, by the time decommissioning is completed. In 1997, the Company made adjustments to the cash flow assumptions at Unit 1 for fuel dry storage, radioactive cost components, property tax and insurance, to more accurately reflect the estimated cost of each cost component. The revisions reduced the total cost estimate by approximately $10 million (in 1998 dollars).

NRC regulations require owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning radioactive portions of nuclear facilities and establish minimum amounts that must be available in such a trust at the time of decommissioning. The annual allowance for Unit 1 and the Company's share of Unit 2 was approximately $23.7 million, for each of the three years ended December 31, 1997. The amount was based upon the 1993 NRC minimum decommissioning cost requirements of $437 million and $198 million (in 1998 dollars) for Unit 1 and the Company's share of Unit 2, respectively. In Opinion No. 95-21, the Company was authorized, until the PSC orders otherwise, to continue to fund to the NRC minimum requirements. PowerChoice permits rate recovery for all radioactive and non-radioactive cost components for both units, including post-shutdown costs, based upon the amounts estimated in the 1995 site specific studies described above, which are higher than the NRC minimum. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. The Company believes that if decommissioning costs are higher than currently estimated, the costs would ultimately be included in the rate process.

Decommissioning costs recovered in rates are reflected in "Accumulated depreciation and amortization" on the balance sheet and amount to $266.8 million and $217.7 million at December 31, 1997 and 1996, respectively for both units. Additionally at December 31, 1997, the fair value of funds accumulated in the Company's external trusts were $164.7 million for Unit 1 and $51.0 million for its share of Unit 2. The trusts are included in "Other property and investments." Earnings on the external trust aggregated $40.3 million through December 31, 1997 and, because the earnings are available to fund decommissioning, have also been included in "Accumulated depreciation and amortization." Amounts recovered for non-radioactive dismantlement are accumulated in an internal reserve fund which has an accumulated balance of $45.2 million at December 31, 1997.

NRC POLICY STATEMENT AND PROPOSAL. The NRC issued a policy statement on the Restructuring and Economic Deregulation of the Electric Utility Industry (the "Policy Statement") in 1997. The Policy Statement addresses the NRC's concerns about the adequacy of decommissioning funds and about the potential impact on operational safety. Current NRC regulations allow a utility to set aside decommissioning funds annually over the estimated life of a plant. The Policy Statement declares the NRC will:

- Continue to conduct reviews of financial qualifications, decommissioning funding and antitrust requirements of nuclear power plants;
- Establish and maintain working relationships with state and federal rate regulators;
- Identify all nuclear power plant owners, indirect as well as direct; and
- Re-evaluate the adequacy of current regulations in light of economic and other changes resulting from rate deregulation.

In addition to the above Policy Statement, the NRC is proposing to amend its regulations on decommissioning funding to reflect conditions expected from deregulation of the electric power industry. The amended rule would:

- Revise the definition of an "electric utility" to reflect changes caused by restructuring within the industry.
- Define a "Federal licensee" as any licensee which has the full faith and credit backing of the United States government. Only such licensees could use statements of intent to meet decommissioning financial assurance requirements for power reactors.
- Require nuclear power plant licensees to report to the NRC on the status of their decommissioning funds at least once every three years and annually within five years of the planned end of operation. NRC's present rule contains no such requirement because State and Federal rate-regulating bodies actively monitor these funds. A deregulated nuclear utility would have no such monitoring.
- Permit nuclear licensees to take credit on earnings for prepaid decommissioning trust funds and external sinking funds from the time the funds are set aside through the end of the decommissioning period. The present rule does not permit such credit because it assumed that inflation and taxes would erode any investment return. NRC has decided, however, that this position is not borne out by historical performance of inflation-adjusted funds invested in U.S. Treasury instruments.

The Company is unable to predict the outcome of this matter.

PSC STAFF'S TENTATIVE CONCLUSIONS ON THE FUTURE OF NUCLEAR GENERATION: On August 27, 1997, the PSC requested comments on its staff's tentative conclusions about how nuclear generation and fossil generation should be treated after decisions are made on the individual electric restructuring agreements currently pending before the PSC. The PSC staff concluded that beyond the transition period (the period covered by the various New York utility restructuring agreements, including PowerChoice), nuclear generation should operate on a competitive basis. In addition, the PSC staff concluded that a sale of generation plants to third parties is the preferred means of determining the fair market-value of generation plants and offers the greatest potential for the mitigation of stranded costs. The PSC staff also concluded that recovery of sunk costs, including post shutdown costs, would be subject to review by the PSC and this process should take into account mitigation measures taken by the utility, including the steps it has taken to encourage competition in its service area.

In October 1997, the majority of utilities with interests in nuclear power plants, including the Company, requested that the PSC reconsider its staff's nuclear proposal. In addition, the utilities raised the following issues: impediments to nuclear plants operating in a competitive mode; impediments to the sale of plants; responsibility for decommissioning and disposal of spent fuel; safety and health concerns; and environmental and fuel diversity benefits. In light of all of these issues, the utilities recommended that a more formal process be developed to address those issues.

The three investor-owned utilities, Rochester Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. and the Company, which are currently pursuing formation of a nuclear operating company in New York State, also filed a response with the PSC in October 1997. The response stated that a forced divestiture of the nuclear plants would add uncertainty to developing a statewide approach to operating the plants and requested that such a forced divestiture proposal be rescinded. The response also stated that implementation of a consolidated six-unit operation would contribute to the mitigation of unrecovered nuclear costs. NYPA, which is also pursuing formation of the nuclear operating company, submitted its own comments which were similar to the comments of the three utilities.

PowerChoice contemplates that the Company's nuclear plants will remain part of the Company's regulated business and that the Company will continue efforts to pursue a statewide solution such as the New York Nuclear Operating Company. The settlement stipulates that absent a statewide solution, the Company will file a detailed plan for analyzing proposed solutions for its nuclear assets, including the feasibility of an auction, transfer and/or divestiture within 24 months of PowerChoice approval. At December 31, 1997, the net book value of the Company's nuclear assets was approximately $1.5 billion, excluding the reserve for decommissioning.

NUCLEAR LIABILITY INSURANCE: The Atomic Energy Act of 1954, as amended, requires the purchase of nuclear liability insurance from the Nuclear Insurance Pools in amounts as determined by the NRC. At the present time, the Company maintains the required $200 million of nuclear liability insurance.

With respect to a nuclear incident at a licensed reactor, the statutory limit for the protection of the public under the Price- Anderson Amendments Act of 1988 which is in excess of the $200 million of nuclear liability insurance, is currently $8.2 billion without the 5% surcharge discussed below. This limit would be funded by assessments of up to $75.5 million for each of the 110 presently licensed nuclear reactors in the United States, payable at a rate not to exceed

$10 million per reactor per year. Such assessments are subject to periodic inflation indexing and to a 5% surcharge if funds prove insufficient to pay claims. With the 5% surcharge included, the statutory limit is $8.6 billion.

The Company's interest in Units 1 and 2 could expose it to a maximum potential loss, for each accident, of $111.8 million (with 5% assessment) through assessments of $14.1 million per year in the event of a serious nuclear accident at its own or another licensed U.S. commercial nuclear reactor. The amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations, whether or not a nuclear incident actually occurs.

NUCLEAR PROPERTY INSURANCE: The Nine Mile Point Nuclear Site has $500 million primary nuclear property insurance with the Nuclear Insurance Pools (ANI/MRP). In addition, there is $2.25 billion in excess of the $500 million primary nuclear insurance with Nuclear Electric Insurance Limited ("NEIL"). The total nuclear property insurance is $2.75 billion. NEIL also provides insurance coverage against the extra expense incurred in purchasing replacement power during prolonged accidental outages. The insurance provides coverage for outages for 156 weeks, after a 21- week waiting period. NEIL insurance is subject to retrospective premium adjustment under which the Company could be assessed up to approximately $11.3 million per loss.

LOW LEVEL RADIOACTIVE WASTE: The Company currently uses the Barnwell, South Carolina waste disposal facility for low level radioactive waste; however, continued access to Barnwell is not assured and the Company has implemented a low level radioactive waste management program so that Unit 1 and Unit 2 are prepared to properly handle interim on-site storage of low level radioactive waste for at least a 10 year period.

Under the Federal Low Level Waste Policy Amendment Act of 1985, New York State was required by January 1, 1993 to have arranged for the disposal of all low level radioactive waste within the state or in the alternative, contracted for the disposal at a facility outside the state. To date, New York State has made no funding available to support siting for a disposal facility.

NUCLEAR FUEL DISPOSAL COST: In January 1983, the Nuclear Waste Policy Act of 1982 (the "Nuclear Waste Act") established a cost of $.001 per KWh of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until the year in which the Company initially plans to ship irradiated fuel to an approved DOE disposal facility. As of December 31, 1997, the Company has recorded a liability of $114.3 million for the disposal of nuclear fuel irradiated prior to 1983. Progress in developing the DOE facility has been slow and it is anticipated that the DOE facility will not be ready to accept deliveries until at least 2010. However, in July 1996, the United States Circuit Court of Appeals for the District of Columbia ruled that the DOE must begin accepting spent fuel from the nuclear industry by January 31, 1998 even though a permanent storage site will not be ready by then. The DOE did not appeal this decision. On January 31, 1997, the Company joined a number of other utilities, states, state agencies and regulatory commissions in filing a suit in the U.S. Court of Appeals for the District of Columbia against the DOE. The suit 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 fuel. On June 3, 1997, the DOE notified utilities that it likely will not meet its January 31, 1998 deadline and that the delay was unavoidable pursuant to the terms of the standard contract with DOE for fuel disposal. DOE also indicated it was not obligated to provide a financial remedy for such unavoidable delay. On November 14, 1997 the United States Court of Appeals for the District of Columbia Circuit issued a writ of mandamus precluding DOE from excusing its own delay on the grounds that it has not yet prepared a permanent repository or interim storage facility. On December 11, 1997, 27 utilities, including the Company, petitioned the DOE to suspend their future payments to the Nuclear Waste Fund until the DOE begins moving fuel from their plant sites. The petition further sought permission to escrow payments to the waste fund beginning in February 1998. On January 12, 1998, the DOE denied the petition. The Company is unable to determine the final outcome of this matter.

The Company has several alternatives under consideration to provide additional storage facilities, as necessary. Each alternative will likely require NRC approval, may require other regulatory approvals and would likely require incurring additional costs, which the Company has included in its decommissioning estimates for both Unit 1 and its share of Unit 2. The Company does not believe that the possible unavailability of the DOE disposal facility until 2010 will inhibit operation of either Unit.

NOTE 4. JOINTLY-OWNED GENERATING FACILITIES

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1997. The Company is required to provide its respective share of financing for any additions to the facilities. Power output and related expenses are shared based on proportionate ownership. The Company's share of expenses associated with these facilities is included in the appropriate operating expenses in the Consolidated Statements of Income. Under PowerChoice, the Company will divest all of its fossil and hydro generation assets with a net book value of $1.1 billion, including its interests in jointly-owned facilities.

		In thousands of dollars		
	Percent Ownership	Utility Plant	Accumulated Depreciation	Construction Work in Progress
Roseton Steam Station Units No. 1 and 2 (a)	25	$ 96,110	$ 54,130	$ 432
Oswego Steam Station Unit No. 6 (b)	76	$ 270,316	$125,089	$ 39
Nine Mile Point Nuclear Station Unit No. 2 (c)	41	$1,507,721	$327,006	$6,748

(a) The remaining ownership interests are Central Hudson Gas and Electric Corporation ("Central Hudson"), the operator of the plant (35%), and Consolidated Edison Company of New York, Inc. (40%). Output of Roseton Units No. 1 and 2, which have a capability of 1,200,000 KW, is shared in the same proportions as the cotenants' respective ownership interests.

(b) The Company is the operator. The remaining ownership interest is Rochester Gas and Electric ("RG&E") (24%). Output of Oswego Unit No. 6, which has a capability of 850,000 KW, is shared in the same proportions as the cotenants' respective ownership interests.

(c) The Company is the operator. The remaining ownership interests are Long Island Lighting Company ("LILCO") (18%), New York State Electric & Gas Corporation ("NYSEG") (18%), RG&E (14%), and Central Hudson (9%). Output of Unit 2, which has a capability of 1,143,000 KW, is shared in the same proportions as the cotenants' respective ownership interests. In June 1997, LILCO and Long Island Power Authority ("LIPA") entered into an agreement, whereby, upon completion of certain transactions, LILCO's stock would be sold to LIPA. It is anticipated that LIPA would own LILCO's 18% ownership interest in Unit 2. In July 1997, the New York State Public Authorities Control Board unanimously approved the agreements related to the LIPA transaction, subject to certain conditions, and LILCO's stockholders subsequently approved this transaction.

NOTE 5. CAPITALIZATION

CAPITAL STOCK

The Company is authorized to issue 185,000,000 shares of common stock, $1 par value; 3,400,000 shares of preferred stock, $100 par value; 19,600,000 shares of preferred stock, $25 par value; and 8,000,000 shares of preference stock, $25 par value. The table below summarizes changes in the capital stock issued and outstanding and the related capital accounts for 1995, 1996 and 1997:

	COMMON STOCK $1 PAR VALUE		PREFERRED STOCK $100 PAR VALUE			PREFERRED STOCK $25 PAR VALUE			CAPITAL STOCK PREMIUM AND EXPENSE (NET)*
	SHARES	AMOUNT*	SHARES	NON-REDEEMABLE*	REDEEMABLE*	SHARES	NON-REDEEMABLE*	REDEEMABLE*	
December 31, 1994:	144,311,466	$144,311	2,376,000	$210,000	$27,600 (a)	12,774,005	$230,000	$89,350 (a)	$1,779,504
Issued	20,657	21	-	-	-	-	-	-	283
Redemptions			(18,000)	-	(1,800)	(366,000)	-	(9,150)	1,319
Foreign currency translation adjustment									3,141
December 31, 1995:	144,332,123	144,332	2,358,000	$210,000	$25,800 (a)	12,408,005	$230,000	$80,200 (a)	$1,784,247
Issued	33,091	33	-	-	-	-	-	-	214
Redemptions			(18,000)	-	(1,800)	(344,000)	-	(8,600)	(28)
Foreign currency translation adjustment									(708)
December 31, 1996:	144,365,214	144,365	2,340,000	$210,000	$24,000 (a)	12,064,005	$230,000	$71,600 (a)	$1,783,725
Issued	54,137	54	-	-	-	-	-	-	426
Redemptions			(18,000)	-	(1,800)	(282,601)	-	(7,070)	104
Foreign currency translation adjustment									(4,567)
December 31, 1997:	144,419,351	$144,419	2,322,000	$210,000	$22,200 (a)	11,781,204	$230,000	$64,530 (a)	$1,779,688

* In thousands of dollars

(a) Includes sinking fund requirements due within one year.

The cumulative amount of foreign currency translation adjustment at December 31, 1997 was $(15,448).

NON-REDEEMABLE PREFERRED STOCK (Optionally Redeemable)

The Company had certain issues of preferred stock which provide for optional redemption at December 31, as follows:

Series	Shares	In thousands of dollars 1997	1996	Redemption price per share (Before adding accumulated dividends)
Preferred $100 par value:				
3.40%	200,000	$20,000	$20,000	$103.50
3.60%	350,000	35,000	35,000	104.85
3.90%	240,000	24,000	24,000	106.00
4.10%	210,000	21,000	21,000	102.00
4.85%	250,000	25,000	25,000	102.00
5.25%	200,000	20,000	20,000	102.00
6.10%	250,000	25,000	25,000	101.00
7.72%	400,000	40,000	40,000	102.36
Preferred $25 par value:				
9.50%	6,000,000	150,000	150,000	25.00 (a)
Adjustable Rate -				
Series A	1,200,000	30,000	30,000	25.00
Series C	2,000,000	50,000	50,000	25.00
		$440,000	$440,000	

(a) Not redeemable until 1999.

MANDATORILY REDEEMABLE PREFERRED STOCK

At December 31, the Company had certain issues of preferred stock, as detailed below, which provide for mandatory and optional redemption. These series require mandatory sinking funds for annual redemption and provide optional sinking funds through which the Company may redeem, at par, a like amount of additional shares (limited to 120,000 shares of the 7.45% series). The option to redeem additional amounts is not cumulative. The Company's five year mandatory sinking fund redemption requirements for preferred stock, in thousands, for 1998 through 2002 are as follows: $10,120; $7,620; $7,620; $7,620 and $3,050, respectively. The aggregate preference of preferred shares upon involuntary liquidation of the Company is the aggregate par value of such shares, plus an amount equal to the dividends accumulated and unpaid on such shares to the date of payment whether or not earned or declared.

	Shares		In thousands of dollars		Redemption price per share (Before adding accumulated dividends)	
Series	1997	1996	1997	1996	1997	Eventual Minimum
Preferred $100 par value:						
7.45%	222,000	240,000	$ 22,200	$ 24,000	$101.69	$100.00
Preferred $25 par value:						
7.85%	731,204	914,005	18,280	22,850	25.28	25.00
8.375%	100,000	200,000	2,500	5,000	25.00	25.00
Adjustable Rate- Series B	1,750,000	1,750,000	43,750	43,750	25.00	25.00
			86,730	95,600		
Less sinking fund requirements			10,120	8,870		
			$ 76,610	$ 86,730		

LONG-TERM DEBT

Long-term debt at December 31 consisted of the following:

		In thousands of dollars	
SERIES	DUE	1997	1996
First mortgage bonds:			
6 1/4%	1997	$ -	$ 40,000
6 1/2%	1998	60,000	60,000
9 1/2%	2000	150,000	150,000
6 7/8%	2001	210,000	210,000
9 1/4%	2001	100,000	100,000
5 7/8%	2002	230,000	230,000
6 7/8%	2003	85,000	85,000
7 3/8%	2003	220,000	220,000
8%	2004	300,000	300,000
6 5/8%	2005	110,000	110,000
9 3/4%	2005	150,000	150,000
7 3/4%	2006	275,000	275,000
*6 5/8%	2013	45,600	45,600
9 1/2%	2021	150,000	150,000
8 3/4%	2022	150,000	150,000
8 1/2%	2023	165,000	165,000
7 7/8%	2024	210,000	210,000
*8 7/8%	2025	75,000	75,000
* 7.2%	2029	115,705	115,705
Total First Mortgage Bonds		2,801,305	2,841,305

Promissory notes:		
*Adjustable Rate Series due		
July 1, 2015	100,000	100,000
December 1, 2023	69,800	69,800
December 1, 2025	75,000	75,000
December 1, 2026	50,000	50,000
March 1, 2027	25,760	25,760
July 1, 2027	93,200	93,200
Term Loan Agreement	105,000	105,000
Unsecured notes payable:		
Medium Term Notes, Various rates, due 2000-2004	20,000	20,000
Other	154,295	156,606
Unamortized premium (discount)	(9,884)	(10,708)
TOTAL LONG-TERM DEBT	3,484,476	3,525,963
Less long-term debt due within one year	67,095	48,084
	$3,417,381	$3,477,879

*Tax-exempt pollution control related issues

Several series of First Mortgage Bonds and Promissory Notes were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $414 million of such securities bear interest at a daily adjustable interest rate (with a Company option to convert to other rates, including a fixed interest rate which would require the Company to issue First Mortgage Bonds to secure the debt) which averaged 3.63% for 1997 and 3.46% for 1996 and are supported by bank direct pay letters of credit. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generating facilities or to refund outstanding tax-exempt bonds and notes (see Note 6).

Other long-term debt in 1997 consists of obligations under capital leases of approximately $29.7 million, a liability to the DOE for nuclear fuel disposal of approximately $114.3 million and a liability for IPP contract terminations of approximately $10.3 million. The aggregate maturities of long-term debt for the five years subsequent to December 31, 1997, excluding capital leases, in millions, are approximately $64, $108, $158, $310 and $230 respectively. The Company's aggregate maturities will increase significantly upon closing of the MRA. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Master Restructuring Agreement and the PowerChoice Agreement."

NOTE 6. BANK CREDIT ARRANGEMENTS

The Company has an $804 million senior debt facility with a bank group consisting of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA discussed in Note 5. As of December 31, 1997, the amount outstanding under the senior debt facility was $529 million, consisting of $105 million under the term loan facility and a $424 million letter of credit, leaving the Company with $275 million of borrowing capability under the facility. The facility expires on June 30, 1999 (subject to earlier termination if the Company separates its fossil/hydro generation business from its transmission and distribution business, or any other significant restructuring plan). The interest rate applicable to the facility is variable based on certain rate options available under the agreement and currently approximates 7.7% (but capped at 15%). The Company is currently negotiating with the lenders to replace the senior debt facility with a larger facility to finance part of the MRA. The Company did not have any short-term debt outstanding at December 31, 1997 and 1996.

NOTE 7. FEDERAL AND FOREIGN INCOME TAXES

See Note 9 - "Tax Assessments."

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1997	1996	1995
United States	$315,027	$269,128	$400,087
Foreign	(1,621)	28,522	17,609
Consolidating eliminations	(3,476)	(17,402)	(10,267)
Income before extraordinary item and income taxes	$309,930	$280,248	$407,429

Following is a summary of the components of Federal and foreign income tax and a reconciliation between the amount of Federal income tax expense reported in the Consolidated Statements of Income and the computed amount at the statutory tax rate:

	In thousands of dollars		
	1997	1996*	1995
Components of Federal and foreign income taxes:			
Current tax expense:			
Federal	$ 77,565	$ 96,011	$ 67,366
Foreign	-	3,708	3,900
	77,565	99,719	71,266
Deferred tax expense:			
Federal	47,836	382	84,002
Foreign	1,194	2,393	4,125
	49,030	2,775	88,127
Total	$126,595	$102,494	$159,393

Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:

Computed tax	$108,475	$ 98,087	$142,601
Increase (reduction) attributable to flow-through of certain tax adjustments:			
Depreciation	36,411	28,103	31,033
Cost of removal	(8,168)	(8,849)	(9,247)
Deferred investment tax credit amortization	(7,454)	(8,018)	(8,589)
Other	(2,669)	(6,829)	3,595
	18,120	4,407	16,792
Federal and foreign income taxes	$126,595	$102,494	$159,393

* Does not include the deferred tax benefit of $36,273 in 1996 associated with the extraordinary item for the discontinuance of regulatory accounting principles.

At December 31, the deferred tax liabilities (assets) were comprised of the following:

	In thousands of dollars	
	1997	1996
Alternative minimum tax	(17,448)	(64,313)
Unbilled revenue	(88,859)	(83,577)
Other	(247,438)	(237,850)
Total deferred tax assets	(353,745)	(385,740)
Depreciation related	1,358,827	1,421,550
Investment tax credit related	79,858	84,294
Other	302,092	237,414
Total deferred tax liabilities	1,740,777	1,743,258
Accumulated deferred income taxes	$1,387,032	$1,357,518

NOTE 8. PENSION AND OTHER RETIREMENT PLANS

The Company and certain of its subsidiaries have non- contributory, defined-benefit pension plans covering substantially all their employees. Benefits are based on the employee's years of service and compensation level. The Company's general policy is to fund the pension costs accrued with consideration given to the maximum amount that can be deducted for Federal income tax purposes.

Net pension cost for 1997, 1996 and 1995 included the following components:

	In thousands of dollars		
	1997	1996	1995
Service cost - benefits earned during the period	$ 27,100	$ 25,000	$ 22,500
Interest cost on projected benefit obligation	75,200	71,700	73,000
Actual return on plan assets	(188,200)	(134,100)	(215,600)
Net amortization and deferral	100,400	55,700	140,300
Total pension cost (1)	$ 14,500	$ 18,300	$ 20,200

(1) $3.2 million for 1997, $3.8 million for 1996, and $4.1 million for 1995 was related to construction labor and, accordingly, was charged to construction projects.

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

	In thousands of dollars	
At December 31,	1997	1996
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$ 990,415	$803,202
Non-vested benefits	73,430	83,107
Accumulated benefit obligations	1,063,845	886,309
Additional amounts related to projected pay increases	108,583	141,472
Projected benefits obligation for service rendered to date	1,172,428	1,027,781
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	(1,304,338)	(1,159,822)
Plan assets in excess of projected benefit obligations	(131,910)	(132,041)
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	(19,446)	(22,005)
Unrecognized net gain from actual return on plan assets different from that assumed	265,100	219,680
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions amortized over 10 years	19,920	66,129
Prior service cost not yet recognized in net periodic pension cost	(50,473)	(49,651)
Pension liability included in the consolidated balance sheets	$ 83,191	$ 82,112

Principle Actuarial Assumptions (%):		
Discount Rate	7.00	7.50
Rate of increase in future compensation levels (plus merit increases)	2.50	2.50
Long-term rate of return on plan assets	9.25	9.25

In addition to providing pension benefits, the Company and its subsidiaries provide certain health care and life insurance benefits for active and retired employees and dependents. Under current policies, substantially all of the Company's employees may be eligible for continuation of some of these benefits upon normal or early retirement.

The Company accounts for the cost of these benefits in accordance with PSC policy requirements which comply with SFAS No. 106. The Company has established various trusts to fund its future postretirement benefit obligation. In 1997, 1996 and 1995, the Company made contributions to such trusts of approximately $13.5 million, $28.5 million and $53.1 million, respectively, which represent the amount received in rates and from cotenants.

Net postretirement benefit cost for 1997, 1996 and 1995 included the following components:

	In thousands of dollars		
	1997	1996	1995
Service cost - benefits attributed to service during the period	$12,300	$12,900	$12,600
Interest cost on accumulated benefit obligation	34,800	37,500	45,400
Actual return on plan assets	(24,500)	(12,900)	(11,200)
Amortization of the transition obligation over 20 years	10,900	13,500	18,800
Net amortization	9,500	6,000	14,600
Total postretirement benefit cost	$43,000	$57,000	$80,200

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

	In thousands of dollars	
At December 31,	1997	1996
Actuarial present value of accumulated benefit obligations:		
Retired and surviving spouses	$392,832	$370,259
Active eligible	43,299	31,030
Active ineligible	83,720	69,441

Accumulated benefit obligation	519,851	470,730
Plan assets at fair value, consisting primarily of listed stocks, bonds and other fixed obligations	(181,101)	(143,071)
Accumulated postretirement benefit obligation in excess of plan assets	338,750	327,659
Unrecognized net loss from past experience different from that assumed and effects of changes in assumptions	(48,466)	(36,048)
Prior service cost not yet recognized in postretirement benefit cost	30,086	39,205
Unrecognized transition obligation being amortized over 20 years	(163,350)	(174,240)
Accrued postretirement benefit liability included in the consolidated balance sheet	$157,020	$156,576

Principal actuarial assumptions (%):		
Discount rate	7.00	7.50
Long-term rate of return on plan assets	9.25	8.00
Health care cost trend rate:		
Pre-65	7.00	8.00
Post-65	6.00	6.50

During 1996, the Company changed the eligibility requirements for plan benefits for employees who retire after May 1, 1996. Generally, plan benefits are now accrued for eligible participants beginning after age 45. Previous to this change, the Company accrued these benefits over the employees' service life. The effect of this change resulted in a decrease in the accumulated benefit obligation for active ineligible employees.

At December 31, 1997, the assumed health cost trend rates gradually decline to 5.0% in 2001. If the health care cost trend rate was increased by one percent, the accumulated postretirement benefit obligation as of December 31, 1997 would increase by approximately 6.7% and the aggregate of the service and interest cost component of net periodic postretirement benefit cost for the year would increase by approximately 5.8%.

The Company recognizes the obligation to provide postemployment benefits if the obligation is attributable to employees' past services, rights to those benefits are vested, payment is probable and the amount of the benefits can be reasonably estimated. At December 31, 1997 and 1996, the Company's postemployment benefit obligation is approximately $13.3 million and $13 million, respectively.

NOTE 9. COMMITMENTS AND CONTINGENCIES

See Note 2.

LONG-TERM CONTRACTS FOR THE PURCHASE OF ELECTRIC POWER: At January 1, 1998, the Company had long-term contracts to purchase electric power from the following generating facilities owned by NYPA:

Facility	Expiration date of contract	Purchased capacity in MW	Estimated annual capacity cost
Niagara - hydroelectric project	2007	951	$27,369,000
St. Lawrence - hydroelectric project	2007	104	1,300,000
Blenheim-Gilboa - pumped storage generating station	2002	270	7,500,000
		1,325	$36,169,000

The purchase capacities shown above are based on the contracts currently in effect. The estimated annual capacity costs are subject to price escalation and are exclusive of applicable energy charges. The total cost of purchases under these contracts and the recently cancelled contract with Fitzpatrick nuclear plant was approximately, in millions, $91.0, $93.3 and $92.5 for the years 1997, 1996 and 1995, respectively. In May 1997, the Company cancelled its commitment to purchase 110 MW of capacity from the Fitzpatrick facility. The Company continues to have a contract with Fitzpatrick to purchase for resale up to 46 MW of power for NYPA's economic development customers.

Under the requirements of PURPA, the Company is required to purchase power generated by IPPs, as defined therein. The Company has 141 PPAs with 148 facilities, of which 143 are on line, amounting to approximately 2,695 MW of capacity at December 31, 1997. Of this amount 2,382 MW is considered firm. The following table shows the payments for fixed and other capacity costs, and energy and related taxes the Company estimates it will be obligated to make under these contracts without giving effect to the MRA.

The payments are subject to the tested capacity and availability of the facilities, scheduling and price escalation.

(In thousands of dollars)

YEAR	SCHEDULABLE FIXED COSTS CAPACITY	SCHEDULABLE FIXED COSTS OTHER	VARIABLE COSTS ENERGY AND TAXES	TOTAL
1998	$247,740	$41,420	$ 906,590	$1,195,750
1999	252,130	42,450	943,720	1,238,300
2000	242,030	44,080	974,080	1,260,190
2001	244,620	45,650	1,042,380	1,332,650
2002	248,940	47,330	1,063,830	1,360,100

The capacity and other fixed costs relate to contracts with 11 facilities, where the Company is required to make capacity and other fixed payments, including payments when a facility is not operating but available for service. These 11 facilities account for approximately 774 MW of capacity, with contract lengths ranging from 20 to 35 years. The terms of these existing contracts allow the Company to schedule energy deliveries from the facilities and then pay for the energy delivered. The Company estimates the fixed payments under these contracts will aggregate to approximately $8 billion over their terms, using escalated contract rates. Contracts relating to the remaining facilities in service at December 31, 1997, require the Company to pay only when energy is delivered, except when the Company decides that it would be better to pay a particular project a reduced energy payment to have the project reduce its high priced energy deliveries as described below. The Company currently recovers schedulable capacity through base rates and energy payments, taxes and other schedulable fixed costs through the FAC. The Company paid approximately $1,106 million, $1,088 million and $980 million in 1997, 1996 and 1995 for 13,500,000 MWh, 13,800,000 MWh and 14,000,000 MWh, respectively, of electric power under all IPP contracts.

On July 9, 1997, the Company announced the MRA to terminate, restate or amend certain IPP power purchase contracts. As a result of negotiations, the MRA currently provides for the termination, restatement or amendment of 28 PPAs with 15 IPPs, in exchange for an aggregate of approximately $3,616 million in cash and 42.9 million shares of the Company's common stock and certain fixed price swap contracts. Under the terms of the MRA, the Company would terminate PPAs representing approximately 1,180 MW of capacity and restate contracts representing 583 MW of capacity. The restated contracts are structured to be in the form of financial swaps with fixed prices for the first two years changing to an indexed pricing formula thereafter. The contract quantities are fixed for the full ten year term of the contracts. The MRA also requires the Company to provide the IPP Parties with a number of fixed price swap contracts with a term of seven years beginning in 2003. The terms of the MRA have been and continue to be modified.

Since 1996, the Company has negotiated 2 long term and several limited term contract amendments whereby the Company can reduce the energy deliveries from the facilities. These reduced energy agreements resulted in a reduction of IPP deliveries of approximately 1,010,000 MWh and 984,000 MWh during 1997 and 1996, respectively.

SALE OF CUSTOMER RECEIVABLES: The Company has established a single-purpose, wholly-owned financing subsidiary, NM Receivables Corp., whose business consists of the purchase and resale of an undivided interest in a designated pool of customer receivables, including accrued unbilled revenues. For receivables sold, the Company has retained collection and administrative responsibilities as agent for the purchaser. As collections reduce previously sold undivided interests, new receivables are customarily sold. NM Receivables Corp. has its own separate creditors which, upon liquidation of NM Receivables Corp., will be entitled to be satisfied out of its assets prior to any value becoming available to the Company. The sale of receivables are in fee simple for a reasonably equivalent value and are not secured loans. Some receivables have been contributed in the form of a capital contribution to NM Receivables Corp. in fee simple for reasonably equivalent value, and all receivables transferred to NM Receivables Corp. are assets owned by NM Receivables Corp. in fee simple and are not available to pay the parent Company's creditors.

At December 31, 1997 and 1996, $144.1 and $250 million, respectively, of receivables had been sold by NM Receivables, Corp. to a third party. The undivided interest in the designated pool of receivables was sold with limited recourse. The agreement provides for a formula based loss reserve pursuant to which additional customer receivables are assigned to the purchaser to protect against bad debts. At December 31, 1997, the amount of additional receivables assigned to the purchaser, as a loss reserve, was approximately $64.4 million. Although this represents the formula- based amount of credit exposure at December 31, 1997 under the agreement, historical losses have been substantially less.

To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser absorbs the excess. Concentrations of credit risk to the purchaser with respect to accounts receivable are limited due to the Company's large, diverse customer base within its service territory. The Company generally does not require collateral, i.e., customer deposits.

TAX ASSESSMENTS: The Internal Revenue Service ("IRS") has conducted an examination of the Company's federal income tax returns for the years 1989 and 1990 and issued a Revenue Agents' Report. The IRS has raised an issue concerning the deductibility of payments made to IPPs in accordance with certain contracts that include a provision for a tracking account. A tracking account represents amounts that these mandated contracts required the Company to pay IPPs in excess of the Company's avoided costs, including a carrying charge. The IRS proposes to disallow a current deduction for amounts paid in excess of the avoided costs of the Company. Although the Company believes that any such disallowances for the years 1989 and 1990 will not have a material impact on its financial position or results of operations, it believes that a disallowance for these above-market payments for the years subsequent to 1990 could have a material adverse affect on its cash flows. To the extent that contracts involving tracking accounts are terminated or restated or amended under the MRA with IPP Parties as described in Note 2, the effects of any proposed disallowance would be mitigated with respect to the IPP Parties covered under the MRA. The Company is vigorously defending its position on this issue. The IRS is currently conducting its examination of the Company's federal income tax returns for the years 1991 through 1993.

ENVIRONMENTAL CONTINGENCIES: The public utility industry typically utilizes and/or generates in its operations a broad range of hazardous and potentially hazardous wastes and by-products. The Company believes it is handling identified wastes and by-products in a manner consistent with federal, state and local requirements and has implemented an environmental audit program to identify any potential areas of concern and aid in compliance with such requirements. The Company is also currently conducting a program to investigate and restore, as necessary to meet current environmental standards, certain properties associated with its former gas manufacturing process and other properties which the Company has learned may be contaminated with industrial waste, as well as investigating identified industrial waste sites as to which it may be determined that the Company contributed. The Company has also been advised that various federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company is currently aware of 124 sites with which it has been or may be associated, including 76 which are Company-owned. The number of owned sites increased as the Company has established a program to identify and actively manage potential areas of concern at its electric substations. This effort resulted in identifying an additional 32 sites. With respect to non-owned sites, the Company may be required to contribute some proportionate share of remedial costs. Although one party can, as a matter of law, be held liable for all of the remedial costs at a site, regardless of fault, in practice costs are usually allocated among PRPs.

Investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) if necessary, determine the appropriate remedial actions and (3) where appropriate, identify other parties who should bear some or all of the cost of remediation. Legal action against such other parties will be initiated where appropriate. After site investigations are completed, the Company expects to determine site-specific remedial actions and to estimate the attendant costs for restoration. However, since investigations are ongoing for most sites, the estimated cost of remedial action is subject to change.

Estimates of the cost of remediation and post-remedial monitoring are based upon a variety of factors, including identified or potential contaminants; location, size and use of the site; proximity to sensitive resources; status of regulatory investigation and knowledge of activities and costs at similarly situated sites. Additionally, the Company's estimating process includes an initiative where these factors are developed and reviewed using direct input and support obtained from the DEC. Actual Company expenditures are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs, as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several. The Company has denied any responsibility at certain of these PRP sites and is contesting liability accordingly.

As a consequence of site characterizations and assessments completed to date and negotiations with PRPs, the Company has accrued a liability in the amount of $220 million, which is reflected in the Company's Consolidated Balance Sheets at December 31, 1997. The potential high end of the range is presently estimated at approximately $650 million, including approximately $285 million in the unlikely event the Company is required to assume 100% responsibility at non-owned sites. The amount accrued at December 31, 1997, incorporates the additional electric substations, previously mentioned, and a change in the method used to estimate the liability for 27 of the Company's largest sites to rely upon a decision analysis approach. This method includes developing several remediation approaches for each of the 27 sites, using the factors previously described, and then assigning a probability to each approach. The probability represents the Company's best estimate of the likelihood of the approach occurring using input received directly from the DEC. The probable costs for each approach are then calculated to arrive at an expected value. While this approach calculates a range of outcomes for each site, the Company has accrued the sum of the expected values for these sites. The amount accrued for the Company's remaining sites is determined through feasibility studies or engineering estimates, the Company's estimated share of a PRP allocation or where no better estimate is available, the low end of a range of possible outcomes. In addition, the Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. PowerChoice provides for the continued application of deferral accounting for cost differences resulting from this effort.

In October 1997, the Company submitted a draft feasibility study to the DEC, which included the Company's Harbor Point site and five surrounding non-owned sites. The study indicates a range of viable remedial approaches, however, a final determination has not been made concerning the remedial approach to be taken. This range consists of a low end of $22 million and a high end of $230 million, with an expected value calculation of $51 million, which is included in the amounts accrued at December 31, 1997. The range represents the total costs to remediate the properties and does not consider contributions from other PRPs. The Company anticipates receiving comments from the DEC on the draft feasibility study by the spring of 1999. At this time, the Company cannot definitively predict the nature of the DEC proposed remedial action plan or the range of remediation costs it will require. While the Company does not expect to be responsible for the entire cost to remediate these properties, it is not possible at this time to determine its share of the cost of remediation. In May 1995, the Company filed a complaint pursuant to applicable Federal and New York State law, in the U.S. District Court for the Northern District of New York against several defendants seeking recovery of past and future costs associated with the investigation and remediation of the Harbor Point and surrounding sites. In a motion currently pending before the court, the New York State Attorney General has moved to dismiss the Company's claims against the State of New York, the New York State Department of Transportation, the Thruway Authority and Canal Corporation. The Company has opposed this motion. The case management order presently calls for the close of discovery on December 31, 1998. As a result, the Company cannot predict the outcome of the pending litigation against other PRPs or the allocation of the Company's share of the costs to remediate the Harbor Point and surrounding sites.

Where appropriate, the Company has provided notices of insurance claims to carriers with respect to the investigation and remediation costs for manufactured gas plant, industrial waste sites and sites for which the Company has been identified as a PRP. To date, the Company has reached settlements with a number of insurance carriers, resulting in payments to the Company of approximately $36 million, net of costs incurred in pursuing recoveries. Under PowerChoice the electric portion or approximately $32 million will be amortized over 10 years. The remaining portion relates to the gas business and is being amortized over the three year settlement period.

CONSTRUCTION PROGRAM: The Company is committed to an ongoing construction program to assure delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1998 through 2002 will require approximately $1.4 billion, excluding AFC and nuclear fuel. For the years 1998 through 2002, the estimates, in millions, are $328, $269, $264, $275 and $300, respectively, which includes $26, $25, $22, $20 and $38, respectively, related to non-nuclear generation. The impact of the ice storm (see Note 13) on the construction program will not be known until restoration efforts have been completed. These amounts are reviewed by management as circumstances dictate.

Under PowerChoice, the Company will separate, through sale or spin-off, the Company's non-nuclear power generation business from the remainder of the business.

GAS SUPPLY, STORAGE AND PIPELINE COMMITMENTS: In connection with its gas business, the Company has long-term commitments with a variety of suppliers and pipelines to purchase gas commodity, provide gas storage capability and transport gas commodity on interstate gas pipelines. The table below sets forth the Company's estimated commitments at December 31, 1997, for the next five years, and thereafter.

(In thousands of dollars)

YEAR	GAS SUPPLY	GAS STORAGE/PIPELINE
1998	$103,990	$95,720
1999	78,380	99,490
2000	56,110	81,550
2001	53,140	60,170
2002	39,860	26,610
Thereafter	155,560	71,130

With respect to firm gas supply commitments, the amounts are based upon volumes specified in the contracts giving consideration for the minimum take provisions. Commodity prices are based on New York Mercantile Exchange quotes and reservation charges, when applicable. For storage and pipeline capacity commitments, amounts are based upon volumes specified in the contracts, and represent demand charges priced at current filed tariffs.

At December 31, 1997, the Company's firm gas supply commitments extend through October 2006, while the gas storage and transportation commitments extend through October 2012. Beginning in May 1996, as a result of a generic rate proceeding, the Company was required to implement service unbundling, where customers could choose to buy natural gas from sources other than the Company. To date the migration has not resulted in any stranded costs since the PSC has allowed utilities to assign the pipeline capacity to the customers choosing another supplier. This assignment is allowed during a three-year period ending March 1999, at which time the PSC will decide on methods for dealing with the remaining unassigned or excess capacity. In September 1997, the PSC indicated that it is unlikely utilities will be allowed to continue to assign pipeline capacity to departing customers after March 1999. The Company is unable to predict how the PSC will resolve these issues.

NOTE 10. FAIR VALUE OF FINANCIAL AND DERIVATIVE FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

CASH AND SHORT-TERM INVESTMENTS: The carrying amount approximates fair value because of the short maturity of the financial instruments.

LONG-TERM DEBT AND MANDATORILY REDEEMABLE PREFERRED STOCK: The fair value of fixed rate long-term debt and redeemable preferred stock is estimated using quoted market prices where available or discounting remaining cash flows at the Company's incremental borrowing rate. The carrying value of NYSERDA bonds and other long-term debt re considered to approximate fair value.

DERIVATIVE FINANCIAL INSTRUMENTS: The fair value of futures and forward contracts are determined using quoted market prices and broker quotes.

The financial instruments held or issued by the Company are for purposes other than trading. The estimated fair values of the Company's financial instruments are as follows:

		In thousands of dollars			
At December 31,		1997		1996	
		Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and short-term investments		$ 378,232	$ 378,232	$ 325,398	$ 325,398
Mandatorily redeemable preferred stock		86,730	87,328	95,600	86,516
Long-term debt:	First Mortgage bonds	2,801,305	2,878,368	2,841,305	2,690,707
	Medium-term notes	20,000	22,944	20,000	21,994
	Promissory notes	413,760	413,760	413,760	413,760
	Other	229,634	229,634	228,461	228,461

In 1997, the Company's energy marketing subsidiary began to engage in both trading and non-trading activities generally using gas futures and electric and gas forward contracts. At December 31, 1997, for both trading and non-trading activities, the fair value of long and short positions was approximately $59.9 million and $57.6 million, respectively. These fair values exceed the weighted average fair value of open positions for the period ending December 31, 1997. The positions above extend for a period of less than one year. With respect to these activities the Company does not have any material counterparty credit risk at December 31, 1997.

Transactions entered into for trading purposes are accounted for on a mark-to-market basis with changes in fair value recognized as a gain or loss in the period of the change. At December 31, 1997, the open trading positions consisted of off-balance sheet electric and gas forward contracts. These positions consisted of long and short electric forward contracts with fair values of $45.3 million (1,878,000 MWh) and $44.3 million (1,778,000 MWh), respectively, and long and short gas forward contracts with fair values of $9.4 million (7.1 million Dth) and $10.2 million (7.3 million Dth), respectively. The quantities above represent notional contract quantities. The effects of trading activities on the Company's 1997 results of operations were not material.

Activities for non-trading purposes generally consist of transactions entered into to hedge the market fluctuations of contractual and anticipated commitments. Gas futures contracts are primarily used for hedging purposes. The change in fair value of these transactions are deferred until the gain or loss on the hedged item is recognized. The fair value of open positions for non-trading purposes at December 31, 1997, as well as the effect of these activities on the Company's results of operations for the same period ending, was not material.

The Company's investments in debt and equity securities consist of trust funds for the purpose of funding the nuclear decommissioning of Unit 1 and its share of Unit 2 (see Note 3 - "Nuclear Plant Decommissioning"), short-term investments held by Opinac Energy Corporation (a subsidiary) and a trust fund for certain pension benefits. The Company has classified all investments in debt and equity securities as available for sale and has recorded all such investments at their fair market value at December 31, 1997. The proceeds from the sale of investments were $159.7 million, $99.4 million and $70.3 million in 1997, 1996 and 1995, respectively. Net realized and unrealized gains and losses related to the nuclear decommissioning trust are reflected in "Accumulated depreciation and amortization" on the Consolidated Balance Sheets, which is consistent with the method used by the Company to account for the decommissioning costs recovered in rates. The unrealized gains and losses related to the investments held by Opinac Energy Corporation and the pension trust are included, net of tax, in "Common stockholders' equity" on the Consolidated Balance Sheets, while the realized gains and losses are included in "Other income and deductions" on the Consolidated Income Statements. The recorded fair values and cost basis of the Company's investments in debt and equity securities is as follows:

At December 31,	1997				1996			
	In thousands of dollars							
Security Type	Cost	Gross Unrealized Gain	(Loss)	Fair Value	Cost	Gross Unrealized Gain	(Loss)	Fair Value
U.S. Government Obligations	$ 14,136	$ 1,864	$ (4)	$ 15,996	$ 24,782	$1,530	$ (33)	$26,279
Commercial Paper	106,035	1,542	-	107,577	90,495	739	-	91,234
Tax Exempt Obligations	80,115	5,884	(55)	85,944	75,590	3,209	(147)	78,652
Corporate Obligations	92,949	17,368	(830)	109,487	62,723	8,524	(422)	70,825
Other	3,025	-	-	3,025	2,586	-	-	2,586
	$296,260	$26,658	$(889)	$322,029	$256,176	$14,002	$ (602)	$269,576

Using the specific identification method to determine cost, the gross realized gains and gross realized losses were:

Year Ended December 31,	1997	1996	1995
	In thousands of dollars		
Realized gains	$3,487	$2,121	$2,523
Realized losses	686	806	328

The contractual maturities of the Company's investments in debt securities is as follows:

At December 31, 1997	Fair Value	Cost
	In thousands of dollars	
Less than 1 year	$106,677	$105,135
1 year to 5 years	10,845	10,654
5 years to 10 years	52,526	50,351
Due after 10 years	113,946	104,353

NOTE 11. STOCK BASED COMPENSATION

Under the Company's stock compensation plans, stock units and stock appreciation rights ("SARs") may be granted to officers, key employees and directors. In addition, the Company's plans allow for the grant of stock options to officers. In 1997, 1996 and 1995 the Company granted 209,918 units and 296,300 SARs, 291,228 units and 376,600 SARs and 169,500 units and 414,000 SARs, respectively. Also, in 1995 the Company granted 85,375 stock options. At December 31, 1997, there were 668,132 units, 1,086,900 SARs and 298,583 options outstanding. Stock units are payable in cash at the end of a defined vesting period, determined at the date of the grant, based upon the Company's stock price for a defined period. SARs become exercisable, as determined at the grant date, and are payable in cash based upon the increase in the Company's stock price from a specified level. As such, for these awards, compensation expense is recognized over the vesting period of the award based upon changes in the Company's stock price for that period. Options were granted over the period 1992 to 1995 and become exercisable three years and expire ten years from the grant date. These options are all considered to be antidilutive for EPS calculations. Included in the results of operations for the years ending 1997 and 1996, is approximately $3.2 and $2.6 million, respectively, related to these plans.

As permitted by SFAS No. 123 - "Accounting for Stock-Based Compensation" ("SFAS No. 123") the Company has elected to follow Accounting Principles Board Opinion No. 25- "Accounting for Stock Issued to Employees" (APB No. 25) and related interpretations in accounting for its employee stock options. Under APB No. 25, no compensation expense is recognized for stock options because the exercise price of the Company's employee stock options equals the market price of the underlying stock on the grant date. Since stock units and SARs are payable in cash, the accounting under APB No. 25 and SFAS No. 123 is the same. Therefore, the pro-forma disclosure of information regarding net income, as required by SFAS No. 123, relates only to the Company's outstanding stock options, the effect of which is immaterial to the financial statements for the years ended 1997, 1996 and 1995. There is no effect on earnings per share for these years resulting from the pro-forma adjustments to net income.

NOTE 12. INFORMATION REGARDING THE ELECTRIC AND GAS BUSINESSES

The Company is engaged principally in the business of production, purchase, transmission, distribution and sale of electricity and the purchase, distribution, sale and transportation of gas in New York State. The Company provides electric service to the public in an area of New York State having a total population of about 3,500,000, including among others, the cities of Buffalo, Syracuse, Albany, Utica, Schenectady, Niagara Falls, Watertown and Troy. The Company distributes or transports natural gas in areas of central, northern and eastern New York having a total population of about 1,700,000 nearly all within the Company's electric service area. Certain information regarding the Company's electric and natural gas segments is set forth in the following table. General corporate expenses, property common to both segments and depreciation of such common property have been allocated to the segments in accordance with the practice established for regulatory purposes. Identifiable assets include net utility plant, materials and supplies, deferred finance charges, deferred recoverable energy costs and certain other regulatory and other assets. Corporate assets consist of other property and investments, cash, accounts receivable, prepayments, unamortized debt expense and certain other regulatory and other assets. At December 31, 1997, total plant assets consisted of approximately 24% Nuclear, 20% Fossil/Hydro, 42% Transmission and Distribution, 11% Gas and 3% Common.

	In thousands of dollars		
	1997	1996	1995
Operating revenues:			
Electric	$3,309,441	$3,308,979	$3,335,548
Gas	656,963	681,674	581,790
Total	$3,966,404	$3,990,653	$3,917,338
Operating income:			
Electric	$ 462,240	$ 438,590	$ 587,282
Gas	96,599	83,748	96,752
Total	$ 558,839	$ 522,338	$ 684,034
Federal and foreign income taxes:			
Electric	96,590	79,574	133,246
Gas	30,005	22,920	26,147
Total	126,595	102,494	159,393
Income before extraordinary item	$ 183,335	$ 177,754	$ 248,036
Depreciation and amortization:			
Electric	$ 311,683	$ 302,825	$ 292,995
Gas	27,958	27,002	24,836
Total	$ 339,641	$ 329,827	$ 317,831
Construction expenditures (including nuclear fuel):			
Electric	$ 221,915	$ 277,505	$ 285,722
Gas	68,842	74,544	60,082
Total	$ 290,757	$ 352,049	$ 345,804
Identifiable assets:			
Electric	$7,257,163	$7,372,370	$7,592,287
Gas	1,185,001	1,203,184	1,123,045
Total	8,442,164	8,575,554	8,715,332
Corporate assets	1,141,977	852,081	762,537
Total assets	$9,584,141	$9,427,635	$9,477,869

NOTE 13. SUBSEQUENT EVENT

In early January 1998, a major ice storm and flooding caused extensive damage in a large area of northern New York. The Company's electric transmission and distribution facilities in an area of approximately 7,000 square miles were damaged, interrupting service to approximately 120,000 of the Company's customers, or approximately 300,000 people. The Company had to rebuild much of its transmission and distribution system to restore power in this area. By the end of January 1998, service to all customers was restored; however, the final costs of the storm will not be known as crews continue to make final repairs to temporary measures to restore service and salvage operations cannot be completed until spring.

The preliminary estimate of the total cost of the restoration and rebuild efforts could exceed $125 million. A portion of the cost will be capitalized; however, at this time, the Company is unable to determine the capital portion until rebuild efforts have been completed and all labor, material and other costs, including charges from other utilities and contractors, have been received and analyzed.

The Company is pursuing federal disaster relief assistance and is working with its insurance carriers to assess what portion of the rebuild costs are covered by insurance policies. The Company is also analyzing potential available options for state financial aid. The Company is unable to determine what recoveries, if any, it may receive from these sources.

Absent recovery, the Company would face a charge to earnings in the first quarter of 1998 to reflect its estimate of unrecoverable, non-capitalized costs.

NOTE 14. QUARTERLY FINANCIAL DATA (UNAUDITED

Operating revenues, operating income, net income (loss) and earnings (loss) per common share by quarters from 1997, 1996 and 1995, respectively, are shown in the following table. The Company, in its opinion, has included all adjustments necessary for a fair presentation of the results of operations for the quarters. Due to the seasonal nature of the utility business, the annual amounts are not generated evenly by quarter during the year. The Company's quarterly results of operations reflect the seasonal nature of its business, with peak electric loads in summer and winter periods. Gas sales peak in the winter.

In thousands of dollars

QUARTER ENDED		OPERATING REVENUES	BASIC AND DILUTED OPERATING INCOME	NET INCOME (LOSS)	BASIC AND DILUTED EARNINGS (LOSS) PER COMMON SHARE
December 31,	1997	$ 960,304	$ 86,024	$ 7,881	$ (.01)
	1996	971,106	117,832	(25,808)	(.24)
	1995	966,478	132,228	27,874	.13
September 30,	1997	$ 896,570	$110,174	$ 31,683	$ .15
	1996	895,713	47,119	(12,916)	(.16)
	1995	887,231	142,732	46,941	.26
June 30,	1997	$ 945,698	$130,704	$ 40,749	$ .22
	1996	960,771	142,755	52,992	.30
	1995	938,816	152,297	54,485	.31
March 31,	1997	$1,163,832	$231,937	$103,022	$ .65
	1996	1,163,063	214,632	96,122	.60
	1995	1,124,813	256,777	118,736	.75

In the fourth quarter of 1996 the Company recorded an extraordinary item for the discontinuance of regulatory accounting principles of $103.6 million (47 cents per common share). In the third quarter of 1996 the Company increased the allowance for doubtful accounts by $68.5 million (31 cents per common share). In the fourth quarter of 1995, the Company recorded $16.9 million (8 cents per common share) for MERIT earned in accordance with the 1991 Agreement.

NOTE 15. ADJUSTMENT OF 1997 FINANCIAL STATEMENTS

On May 29, 1998, after discussion with the Staff of the Securities and Exchange Commission, the Company determined that the $190 million limitation on the recoverability of the MRA regulatory asset, as discussed in Note 2 - "Rate and Regulatory Issues and Contingencies," should be charged to expense in the quarter in which the MRA closes. Accordingly, the 1997 financial statements, as presented herein, have been restated to eliminate the $190 million charge (85 cents per share) and the Company expects that the second quarter 1998 financial statements will reflect such $190 million charge.

ELECTRIC AND GAS STATISTICS

ELECTRIC CAPABILITY

	Thousands of KW			
December 31,	1997	%	1996	1995
Owned:				
Coal	1,360	16.7	1,333	1,316
Oil*	646	7.9	636	636
Dual Fuel - Oil/Gas	700	8.6	700	700
Nuclear	1,082	13.3	1,082	1,082
Hydro	661	8.1	617	665
	4,449	54.6	4,368	4,399
Purchased:				
New York Power Authority				
- Hydro	1,325	16.2	1,310	1,325
- Nuclear	-	-	110	110
IPPs	2,382	29.2	2,406	2,390
	3,707	45.4	3,826	3,825
Total capability**	8,156	100.0	8,194	8,224
Electric peak load	6,348		6,021	6,211

* In 1994, Oswego Unit No. 5 (an oil-fired unit with a capability of 850,000 KW) was put into long-term cold standby, but could be returned to service in three months.

** Available capability can be increased during heavy load periods by purchases from neighboring interconnected systems. Hydro station capability is based on average December streamflow conditions.

ELECTRIC STATISTICS

	1997	1996	1995
Electric sales (Millions of KWh):			
Residential	9,905	10,109	10,055
Commercial	11,552	11,564	11,613
Industrial	7,191	7,148	7,061
Industrial-Special	4,507	4,326	4,053
Municipal service	235	246	229
Other electric systems	3,746	5,431	4,305
Subsidiary	-	303	368
	37,136	39,127	37,684
Electric revenues (Thousands of dollars):			
Residential	$1,227,245	$1,252,165	$1,214,848
Commercial	1,233,417	1,237,385	1,237,502
Industrial	531,164	524,858	523,996
Industrial-Special	61,820	58,444	56,250
Municipal service	54,545	53,795	50,860
Other electric systems	83,794	113,391	88,936
Miscellaneous	117,456	53,698	143,625
Subsidiary	-	15,243	19,531
	$3,309,441	$3,308,979	$3,335,548
Electric customers (Average):			
Residential	1,404,345	1,405,083	1,399,725
Commercial	146,039	145,149	144,731
Industrial	1,970	2,045	2,122
Industrial-Special	85	99	83
Other	1,519	1,302	1,488
Subsidiary	-	13,557	13,508
	1,553,958	1,567,235	1,561,657
Residential (Average):			
Annual KWh use per customer	7,053	7,195	7,184
Cost to customer per KWh (in cents)	12.39	12.39	12.08
Annual revenue per customer	$873.89	$891.17	$867.92

GAS STATISTICS

	1997	1996	1995
Gas Sales (Thousands of Dth):			
Residential	55,203	56,728	51,842
Commercial	22,069	25,353	23,818
Industrial	1,381	2,770	2,660
Other gas systems	28	30	161
Total sales	78,681	84,881	78,481
Spot market	2,451	10,459	1,723
Transportation of customer-owned gas	152,813	134,671	144,613
Total gas delivered	233,945	230,011	224,817
Gas Revenues (Thousands of dollars):			
Residential	$ 436,136	$ 417,348	$ 368,391
Commercial	148,213	162,275	143,643
Industrial	6,549	13,325	11,530
Other gas systems	130	138	762
Spot market	6,346	37,124	3,096
Transportation of customer-owned gas	55,657	50,381	48,290
Miscellaneous	3,932	1,083	6,078
	$ 656,963	$ 681,674	$ 581,790
Gas Customers (Average):			
Residential	484,862	477,786	471,948
Commercial	40,955	41,266	40,945
Industrial	186	206	225
Other	6	6	1
Transportation	843	713	652
	526,852	519,977	513,771
Residential (Average):			
Annual dekatherm use per customer	113.9	118.7	109.8
Cost to customer per Dth	$ 7.90	$ 7.36	$ 7.11
Annual revenue per customer	$899.51	$873.50	$780.58
Maximum day gas sendout (Dth)	1,133,370	1,152,996	1,211,252

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) Certain documents filed as part of the Form 10-K.

(1) INDEX OF FINANCIAL STATEMENTS

Report of Independent Accountants

Consolidated Statements of Income and Retained Earnings for each of the three years in the period ended December 31, 1997
Consolidated Balance Sheets at December 31, 1997 and 1996
Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 1997
Notes to Consolidated Financial Statements

Separate financial statements of the Company have been omitted since it is primarily an operating company and all consolidated subsidiaries are wholly-owned directly or by subsidiaries.

(2) The following financial statement schedules of the Company for the years ended December 31, 1997, 1996 and 1995 are included:

Report of Independent Accountants on Financial Statement Schedule

Consolidated Financial Statement Schedule:

II--Valuation and Qualifying Accounts and Reserves

The Financial Statement Schedule above should be read in conjunction with the Consolidated Financial Statements in Part II, Item 8 (Financial Statements and Supplementary Data).

Schedules other than those mentioned above are omitted because the conditions requiring their filing do not exist or because the required information is given in the financial statements, including the notes thereto.

(3) List of Exhibits:

See Exhibit Index.

(b) Reports on Form 8-K:

Form 8-K Reporting Date - October 10, 1997
Item reported - Item 5. Other Events.
Registrant filed information concerning the PowerChoice settlement.

Form 8-K Reporting Date - February 11, 1998
Item reported - Item 5. Other Events.
Registrant filed information concerning the January 1998 ice storm.

(c) Exhibits.

See Exhibit Index.

(d) Financial Statement Schedule.

See (a)(2) above.

REPORT OF INDEPENDENT ACCOUNTANTS ON
FINANCIAL STATEMENT SCHEDULE

To the Board of Directors of
Niagara Mohawk Power Corporation

Our audits of the consolidated financial statements of Niagara Mohawk Power Corporation referred to in our report dated March 26, 1998 appearing in this Form 10-K also included an audit of the Financial Statement Schedule listed in Item 14(a) of this Form 10- K. In our opinion, this Financial Statement Schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PRICE WATERHOUSE LLP

Syracuse, New York
March 26, 1998

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

(In Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (a)	Balance at End of Period
Allowance for Doubtful Accounts - deducted from Accounts Receivable in the Consolidated Balance Sheets					
1997	$52,096	$ 46,549	$ 3,000 (b)	$39,097	$62,548
1996	20,000	127,648	800 (b)	96,352	52,096
1995	3,600	31,284	16,400 (b)	31,284	20,000

(a) Uncollectible accounts written off net of recoveries of $14,416, $12,842, and $10,830 in 1997, 1996 and 1995, respectively.

(b) The Company increased its allowance for doubtful accounts in 1995 and recorded a regulatory asset of $16,400, which reflects the amount that the Company expects to recover in rates. In 1996, regulatory asset increased by $800 to $17,200 and in 1997, regulatory asset increased $3,000 to $20,200.

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

(In Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period (c)
Miscellaneous Valuation Reserves					
1997	$37,740	$ 2,207	$ -	$ 4,049	$35,898
1996	39,426	10,261	-	11,947	37,740
1995	29,197	18,719	-	8,490	39,426

(c) The reserves relate primarily to certain inventory and non-rate base properties.

NIAGARA MOHAWK POWER CORPORATION

EXHIBIT INDEX

In the following exhibit list, NMPC refers to the Company and CNYP refers to Central New York Power Corporation, a predecessor company. Each document referred to below is incorporated by reference to the files of the Commission, unless the reference to the document in the list is preceded by an asterisk. Previous filings with the Commission are indicated as follows:

A--NMPC Registration Statement No. 2-8214;
C--NMPC Registration Statement No. 2-8634;
F--CNYP Registration Statement No. 2-3414;
G--CNYP Registration Statement No. 2-5490;
V--NMPC Registration Statement No. 2-10501;
X--NMPC Registration Statement No. 2-12443;
Z--NMPC Registration Statement No. 2-13285;
CC--NMPC Registration Statement No. 2-16193;
DD--NMPC Registration Statement No. 2-18995;
GG--NMPC Registration Statement No. 2-25526;
HH--NMPC Registration Statement No. 2-26918;
II--NMPC Registration Statement No. 2-29575;
JJ--NMPC Registration Statement No. 2-35112;
KK--NMPC Registration Statement No. 2-38083;
OO--NMPC Registration Statement No. 2-49570;
QQ--NMPC Registration Statement No. 2-51934;
SS--NMPC Registration Statement No. 2-52852;
TT--NMPC Registration Statement No. 2-54017;
VV--NMPC Registration Statement No. 2-59500;
CCC--NMPC Registration Statement No. 2-70860;
III--NMPC Registration Statement No. 2-90568;
OOO--NMPC Registration Statement No. 33-32475;
PPP--NMPC Registration Statement No. 33-38093;
QQQ--NMPC Registration Statement No. 33-47241;
RRR--NMPC Registration Statement No. 33-59594;

b--NMPC Annual Report on Form 10-K for year ended December 31, 1990; and
c--NMPC Annual Report on Form 10-K for year ended December 31, 1992; and
d--NMPC Annual Report on Form 10-K for year ended December 31, 1993; and
e--NMPC Annual Report on Form 10-K for year ended December 31, 1994; and
f--NMPC Annual Report on Form 10-K for year ended December 31, 1995; and
g--NMPC Annual Report on Form 10-K for year ended December 31, 1996.
h--NMPC Quarterly Report on Form 10-Q for quarter ended March 31, 1993; and
i--NMPC Quarterly Report on Form 10-Q for quarter ended September 30, 1993; and
j--NMPC Quarterly Report on Form 10-Q for quarter ended June 30, 1995; and
k--NMPC Quarterly Report on Form 10-Q for quarter ended September 30, 1996;
l--NMPC Quarterly Report on Form 10-Q for quarter ended June 30, 1997; and
m--NMPC Quarterly Report on Form 10-Q for quarter ended September 30, 1997.
n--NMPC Report on Form 8-K dated July 9, 1997; and
o--NMPC Report on Form 8-K dated October 10, 1997.

In accordance with Paragraph 4(iii) of Item 601 (b) of Regulation S-K, the Company agrees to furnish to the Securities and Exchange Commission, upon request, a copy of the agreements comprising the $804 million senior debt facility that the Company completed with a bank group during March 1996. The total amount of long-term debt authorized under such agreement does not exceed 10 percent of the total consolidated assets of the Company and its subsidiaries.

		INCORPORATION BY REFERENCE	
EXHIBIT NO.	DESCRIPTION OF INSTRUMENT	PREVIOUS FILING	PREVIOUS EXHIBIT DESIGNATION
3(a)(1)	--Certificate of Consolidation of New York Power and Light Corporation, Buffalo Niagara Electric Corporation and Central New York Power Corporation, filed in the office of the New York Secretary of State, January 5, 1950.	e	3(a)(1)
3(a)(2)	--Certificate of Amendment of Certificate of Incorporation of NMPC, filed in the office of the New York Secretary of State, January 5, 1950.	e	3(a)(2)
3(a)(3)	--Certificate of Amendment of Certificate of Incorporation of NMPC, pursuant to Section 36 of the Stock Corporation Law of New York, filed August 22, 1952, in the office of the New York Secretary of State.	e	3(a)(3)
3(a)(4)	--Certificate of NMPC pursuant to Section 11 of the Stock Corporation Law of New York filed May 5, 1954 in the office of the New York Secretary of State.	e	3(a)(4)
3(a)(5)	--Certificate of Amendment of Certificate of Incorporation of NMPC, pursuant to Section 36 of the Stock Corporation Law of New York, filed January 9, 1957 in the office of the New York Secretary of State.	e	3(a)(5)
3(a)(6)	--Certificate of NMPC pursuant to Section 11 of the Stock Corporation Law of New York, filed May 22, 1957 in the office of the New York Secretary of State.	e	3(a)(6)
3(a)(7)	--Certificate of NMPC pursuant to Section 11 of the Stock Corporation Law of New York, filed February 18, 1958 in the office of the New York Secretary of State.	e	3(a)(7)
3(a)(8)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 5, 1965 in the office of the New York Secretary of State.	e	3(a)(8)
3(a)(9)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 24, 1967 in the office of the New York Secretary of State.	e	3(a)(9)
3(a)(10)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 19, 1968 in the office of the New York Secretary of State.	e	3(a)(10)
3(a)(11)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed September 22, 1969 in the office of the New York Secretary of State.	e	3(a)(11)
3(a)(12)	--Certificate of Amendment of Certificate		

	of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 12, 1971 in the office of the New York Secretary of State.	e	3(a)(12)
3(a)(13)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 18, 1972 in the office of the New York Secretary of State.	e	3(a)(13)
3(a)(14)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed June 26, 1973 in the office of the New York Secretary of State.	e	3(a)(14)
3(a)(15)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 9, 1974 in the office of the New York Secretary of State.	e	3(a)(15)
3(a)(16)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed March 12, 1975 in the office of the New York Secretary of State.	e	3(a)(16)
3(a)(17)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 7, 1975 in the office of the New York Secretary of State.	e	3(a)(17)
3(a)(18)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed August 27, 1975 in the office of the New York Secretary of State.	e	3(a)(18)
3(a)(19)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York, filed May 7, 1976 in the office of the New York Secretary of State.	e	3(a)(19)
3(a)(20)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed September 28, 1976 in the office of the New York Secretary of State.	e	3(a)(20)
3(a)(21)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed January 27, 1978 in the office of the New York Secretary of State.	e	3(a)(21)
3(a)(22)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 8, 1978 in the office of the New York Secretary of State.	e	3(a)(22)
3(a)(23)	--Certificate of Correction of the Certificate of Amendment filed May 7, 1976 of the Certificate of Incorporation under Section 105 of the Business Corporation Law of New York filed July 13, 1978 in the office of the		

	New York Secretary of State.	e	3(a)(23)
3(a)(24)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed July 17, 1978 in the office of the New York Secretary of State.	e	3(a)(24)
3(a)(25)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed March 3, 1980 in the office of the New York Secretary of State.	e	3(a)(25)
3(a)(26)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed March 31, 1981 in the office of the New York Secretary of State.	e	3(a)(26)
3(a)(27)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed March 31, 1981 in the office of the New York Secretary of State.	e	3(a)(27)
3(a)(28)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed April 22, 1981 in the office of the New York Secretary of State.	e	3(a)(28)
3(a)(29)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 8, 1981 in the office of the New York Secretary of State.	e	3(a)(29)
3(a)(30)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed April 26, 1982 in the office of the New York Secretary of State.	e	3(a)(30)
3(a)(31)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed January 24, 1983 in the office of the New York Secretary of State.	e	3(a)(31)
3(a)(32)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed August 3, 1983 in the office of the New York Secretary of State.	e	3(a)(32)
3(a)(33)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed December 27, 1983 in the office of the New York Secretary of State.	e	3(a)(33)
3(a)(34)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed December 27, 1983 in the office of the New York Secretary of State.	e	3(a)(34)
3(a)(35)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of		

	New York filed June 4, 1984 in the office of the New York Secretary of State.	e	3(a)(35)
3(a)(36)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed August 29, 1984 in the office of the New York Secretary of State.	e	3(a)(36)
3(a)(37)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed April 17, 1985, in the office of the New York Secretary of State.	e	3(a)(37)
3(a)(38)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 3, 1985, in the office of the New York Secretary of State.	e	3(a)(38)
3(a)(39)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed December 24, 1986 in the office of the New York Secretary of State.	e	3(a)(39)
3(a)(40)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed June 1, 1987 in the office of the New York Secretary of State.	e	3(a)(40)
3(a)(41)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed July 16, 1987 in the office of the New York Secretary of State.	e	3(a)(41)
3(a)(42)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 27, 1988 in the office of the New York Secretary of State.	e	3(a)(42)
3(a)(43)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed September 27, 1990 in the office of the New York Secretary of State.	e	3(a)(43)
3(a)(44)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed October 18, 1991 in the office of the New York Secretary of State.	e	3(a)(44)
3(a)(45)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed May 5, 1994 in the office of the New York Secretary of State.	e	3(a)(45)
3(a)(46)	--Certificate of Amendment of Certificate of Incorporation of NMPC under Section 805 of the Business Corporation Law of New York filed August 5, 1994 in the office of the New York Secretary of State.	e	3(a)(46)
*3(b)	--By-Laws of NMPC, as amended February 26, 1998.		

4(a)	--Agreement to furnish certain debt instruments.	e	4(b)
4(b)(1)	--Mortgage Trust Indenture dated as of October 1, 1937 between NMPC (formerly CNYP) and Marine Midland Bank, N.A. (formerly named The Marine Midland Trust Company of New York), as Trustee.	F	**

** Filed October 15, 1937 after effective date of Registration Statement No. 2-3414.

4(b)(2)	--Supplemental Indenture dated as of December 1, 1938, supplemental to Exhibit 4(1).	VV	2-3
4(b)(3)	--Supplemental Indenture dated as of April 15, 1939, supplemental to Exhibit 4(1).	VV	2-4
4(b)(4)	--Supplemental Indenture dated as of July 1, 1940, supplemental to Exhibit 4(1).	VV	2-5
4(b)(5)	--Supplemental Indenture dated as of October 1, 1944, supplemental to Exhibit 4(1).	G	7-6
4(b)(6)	--Supplemental Indenture dated as of June 1, 1945, supplemental to Exhibit 4(1).	VV	2-8
4(b)(7)	--Supplemental Indenture dated as of August 17, 1948, supplemental to Exhibit 4(1).	VV	2-9
4(b)(8)	--Supplemental Indenture dated as of December 31, 1949, supplemental to Exhibit 4(1).	A	7-9
4(b)(9)	--Supplemental Indenture dated as of January 1, 1950, supplemental to Exhibit 4(1).	A	7-10
4(b)(10)	--Supplemental Indenture dated as of October 1, 1950, supplemental to Exhibit 4(1).	C	7-11
4(b)(11)	--Supplemental Indenture dated as of October 19, 1950, supplemental to Exhibit 4(1).	C	7-12
4(b)(12)	--Supplemental Indenture dated as of February 20, 1953, supplemental to Exhibit 4(1).	V	4-16
4(b)(13)	--Supplemental Indenture dated as of April 25, 1956, supplemental to Exhibit 4(1).	X	4-19
4(b)(14)	--Supplemental Indenture dated as of March 15, 1960, supplemental to Exhibit 4(1).	CC	2-23
4(b)(15)	--Supplemental Indenture dated as of October 1, 1966, supplemental to Exhibit 4(1).	GG	2-27
4(b)(16)	--Supplemental Indenture dated as of July 15, 1967, supplemental to Exhibit 4(1).	HH	4-29

4(b)(17)	--Supplemental Indenture dated as of August 1, 1967, supplemental to Exhibit 4(1).	HH	4-30
4(b)(18)	--Supplemental Indenture dated as of August 1, 1968, supplemental to Exhibit 4(1).	II	2-30
4(b)(19)	--Supplemental Indenture dated as of March 15, 1977, supplemental to Exhibit 4(1).	VV	2-39
4(b)(20)	--Supplemental Indenture dated as of August 1, 1977, supplemental to Exhibit 4(1).	CCC	4(b)(40)
4(b)(21)	--Supplemental Indenture dated as of March 1, 1978, supplemental to Exhibit 4(1).	CCC	4(b)(42)
4(b)(22)	--Supplemental Indenture dated as of June 15, 1980, supplemental to Exhibit 4(1).	CCC	4(b)(46)
4(b)(23)	--Supplemental Indenture dated as of November 1, 1985, supplemental to Exhibit 4(1).	III	4(b)(64)
4(b)(24)	--Supplemental Indenture dated as of October 1, 1989, supplemental to Exhibit 4(1).	OOO	4(b)(73)
4(b)(25)	--Supplemental Indenture dated as of June 1, 1990, supplemental to Exhibit 4(1).	PPP	4(b)(74)
4(b)(26)	--Supplemental Indenture dated as of November 1, 1990, supplemental to Exhibit 4(1).	PPP	4(b)(75)
4(b)(27)	--Supplemental Indenture dated as of March 1, 1991, supplemental to Exhibit 4(1).	QQQ	4(b)(76)
4(b)(28)	--Supplemental Indenture dated as of October 1, 1991, supplemental to Exhibit 4(1).	QQQ	4(b)(77)
4(b)(29)	--Supplemental Indenture dated as of April 1, 1992, supplemental to Exhibit 4(1).	QQQ	4(b)(78)
4(b)(30)	--Supplemental Indenture dated as of June 1, 1992, supplemental to Exhibit 4(1).	RRR	4(b)(79)
4(b)(31)	--Supplemental Indenture dated as of July 1, 1992, supplemental to Exhibit 4(1).	RRR	4(b)(80)
4(b)(32)	--Supplemental Indenture dated as of August 1, 1992, supplemental to Exhibit 4(1).	RRR	4(b)(81)
4(b)(33)	--Supplemental Indenture dated as of April 1, 1993, supplemental to Exhibit 4(1).	h	4(b)(82)
4(b)(34)	--Supplemental Indenture dated as of July 1, 1993, supplemental to		

	Exhibit 4(1).	i	4(b)(83)
4(b)(35)	--Supplemental Indenture dated as of September 1, 1993, supplemental to Exhibit 4(1).	i	4(b)(84)
4(b)(36)	--Supplemental Indenture dated as of March 1, 1994, supplemental to Exhibit 4(1).	d	4(b)(85)
4(b)(37)	--Supplemental Indenture dated as of July 1, 1994, supplemental to Exhibit 4(1).	e	4(86)
4(b)(38)	--Supplemental Indenture dated as of May 1, 1995, supplemental to Exhibit 4(1).	j	4(87)
4(b)(39)	--Agreement dated as of August 16, 1940, between CNYP, The Chase National Bank of the City of New York, as Successor Trustee, and The Marine Midland Trust Company of New York, as Trustee.	G	7-23
10-1	--Agreement dated March 1, 1957 between the Power Authority of the State of New York and NMPC as to sale, transmission and disposition of St. Lawrence power.	Z	13-11
10-2	--Agreement dated February 10, 1961 between the Power Authority of the State of New York and NMPC as to sale, transmission and disposition of Niagara redevelopment power.	DD	13-6
10-3	--Agreement dated July 26, 1961 between the Power Authority of the State of New York and NMPC supplemental to Exhibit 10-2.	DD	13-7
10-4	--Agreement dated as of March 23, 1973 between the Power Authority of the State of New York and NMPC as to the sale, transmission and disposition of Blenheim-Gilboa power.	OO	5-8
10-5	--Agreement dated January 23, 1970 between Consolidated Gas Supply Corporation (formerly named New York State Natural Gas Corporation) and NMPC.	KK	5-8
10-6a	--New York Power Pool Agreement dated as of February 1, 1974 between NMPC and six other New York utilities and the Power Authority of the State of New York.	QQ	5-10
10-6b	--New York Power Pool Agreement dated as of April 27, 1975 between NMPC and six other New York electric utilities and the Power Authority of the State of New York (the parties to the Agreement have petitioned the Federal Power Commission for an order permitting such Agreement, which increases the reserve factor of all parties from .14 to .18, to supersede the New York Power Pool Agreement dated as of February 1, 1974).	TT	5-10b

10-7	--Agreement dated as of October 31, 1968 between NMPC, Central Hudson Gas & Electric Corporation and Consolidated Edison Company of New York, Inc. as to Joint Electric Generating Plant (the Roseton Station).	JJ	5-10
10-8a	--Memorandum of Understanding dated as of May 30, 1975 between NMPC and Rochester Gas & Electric Corporation with respect to Oswego Unit No. 6.	SS	5-13
10-8b	--Memorandum of Understanding dated as of May 30, 1975 between NMPC and Rochester Gas and Electric Corporation with respect to Oswego Unit No. 6.	SS	5-13
10-8c	--Basic Agreement dated as of September 22, 1975 between NMPC and Rochester Gas and Electric Corporation with respect to Oswego Unit No. 6.	VV	5-13b
10-9a	--Memorandum of Understanding dated as of May 30, 1975 between NMPC and four other New York electric utilities with respect to Nine Mile Point Nuclear Station Unit No. 2.	SS	5-14
10-9b	--Basic Agreement dated as of September 22, 1975 between NMPC and four other New York electric utilities with respect to Nine Mile Point Nuclear Station Unit No. 2.	VV	5-14b
10-9c	--Nine Mile Point Nuclear Station Unit No. 2 Operating Agreement.	c	10-19
10-10a	--Memorandum of Understanding dated as of May 16, 1974, as amended May 30, 1975, between NMPC and three other New York electric utilities with respect to the Sterling Nuclear Station.	SS	5-15
10-10b	--Basic Agreement dated as of September 22, 1975 between NMPC and three other New York electric utilities with respect to the Sterling Nuclear Stations.	VV	5-15b
10-11	--Master Restructuring Agreement, dated as of July 9, 1997, between the Company and the sixteen independent power producers signatory thereto.	n	10.28
10-12	--PowerChoice settlement filed with the PSC on October 10, 1997	o	99-9
*10-13	--PSC Opinion and Order regarding approval of the PowerChoice settlement agreement with PSC, issued and effective March 20, 1998.		
*10-14	--Preferred Consent, December, 1997		
(A)10-15	--NMPC Officers' Incentive Compensation Plan - Plan Document.	b	10-16
(A)10-16	--NMPC Long Term Incentive Plan - Plan Document.	l	10-1
(A)10-17	--NMPC Management Incentive Compensation Plan -		

	Plan Document.	b	10-17
(A)10-18	--CEO Special Award Plan.	l	10-2
(A)10-19	--NMPC Deferred Compensation Plan.	d	10-16
*(A)10-20	--Amendment to NMPC Deferred Compensation Plan		
(A)10-21	--NMPC Performance Share Unit Plan.	d	10-17
(A)10-22	--NMPC 1992 Stock Option Plan.	d	10-18

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(A)10-23	--NMPC 1995 Stock Incentive Plan	f	10-31
(A)10-24	--Employment Agreement between NMPC and David J. Arrington, Sr. Vice President, Human Resources, dated December 20, 1996.	g	10-17
(A)10-25	--Employment Agreement between NMPC and Albert J. Budney, Jr., President and Chief Operating Officer, December 20, 1996.	g	10-18
(A)10-26	--Employment Agreement between NMPC and William E. Davis, Chairman of the Board and Chief Executive Officer, dated December 20, 1996.	g	10-19
(A)10-27	--Employment Agreement between NMPC and Darlene D. Kerr, Sr. Vice President, Energy Distribution, dated December 20, 1996.	g	10-20
(A)10-28	--Employment Agreement between NMPC and Gary J. Lavine, Sr. Vice President, Legal and Corporate Relations, dated December 20, 1996.	g	10-21
(A)10-29	--Employment Agreement between NMPC and John W. Powers, Sr. Vice President, and Chief Executive Officer, dated December 20, 1996.	g	10-22
(A)10-30	--Employment Agreement between NMPC and B. Ralph Sylvia, Executive Vice President, Electric Generation and Chief Nuclear Officer, dated December 20, 1996.	g	10-23
(A)10-31	--Employment Agreement between NMPC and Theresa A. Flaim, Vice President - Corporate Strategic Planning, dated December 20, 1996.	g	10-24
(A)10-32	--Employment Agreement between NMPC and Steven W. Tasker, Vice President - Controller, dated December 20, 1996.	g	10-25
(A)10-33	--Employment Agreement between NMPC and Kapua A. Rice, Corporate Secretary, dated December 20, 1996.	g	10-26
(A)10-34	--Amendment to Employment Agreement between NMPC and David J. Arrington, Albert J. Budney, Jr., William E. Davis, Darlene D. Kerr, Gary J. Lavine, John W. Powers and B. Ralph Sylvia, dated June 9, 1997.	l	10-3
(A)10-35	--Employment Agreement between NMPC and William F. Edwards, dated September 25, 1997.	m	10-4
*(A)10-36	--Employment Agreement between NMPC and		

John H. Mueller, dated January 19, 1998.

(A)10-37	--Deferred Stock Unit Plan for Outside Directors g	10-27
*11	--Statement setting forth the computation of average number of shares of common stock outstanding.	
*12	--Statements Showing Computations of Certain Financial Ratios.	
*21	--Subsidiaries of the Registrant.	
*23	--Consent of Price Waterhouse LLP, independent accountants.	
*27	-- Financial Data Schedule.	

(A) Management contract or compensatory plan or arrangement required to be filed as an exhibit pursuant to Item 601 of Regulation S-K.

EXHIBIT 11

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARIES

COMPUTATION OF AVERAGE NUMBER OF SHARES OF COMMON STOCK OUTSTANDING

Year Ended December 31,	(1) Shares of Common Stock	(2) Number of Days Outstanding	(3) Share Days (2 x 1)	Average Number of Shares Outstanding as Shown on Consolidated Statements of Income (3 Divided by Number of Days in Year)
1997				
January 1 - December 31	144,365,214	365	52,693,303,110	
Shares issued at various times during the period - Acquisition - Syracuse Suburban Gas Company, Inc.	54,137	*	14,260,096	
	144,419,351		52,707,563,206	144,404,283
1996				
January 1 - December 31	144,332,123	366	52,825,557,018	
Shares issued at various times during the year -				
Acquisition - Syracuse Suburban Gas Company, Inc.	33,091	*	6,397,653	
	144,365,214		52,831,954,671	144,349,603
1995				
January 1 - December 31	144,311,466	365	52,673,685,090	
Shares issued -				
Dividend Reinvestment Plan - January 31	19,016	335	6,370,360	
Acquisition - Syracuse Suburban Gas Company, Inc. - October 4	1,641	89	146,049	
	144,332,123		52,680,201,499	144,329,319

* Number of days outstanding not shown as shares represent an accumulation of weekly, monthly and quarterly issues throughout the year. Share days for shares issued are based on the total number of days each share was outstanding during the year.

Note: Earnings per share calculated on both a basic and diluted basis are the same due to the effects of rounding.

EXHIBIT 12

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

STATEMENT SHOWING COMPUTATIONS OF RATIO OF EARNINGS TO FIXED CHARGES, RATIO OF EARNINGS TO FIXED CHARGES WITHOUT AFC AND RATIO OF EARNINGS TO FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Year Ended December 31,				
	1997	1996	1995	1994	1993
A. Net Income per Statements of Income	$183,335	$110,390	$248,036	$176,984	$271,831
B. Taxes Based on Income or Profits	126,595	66,221	159,393	111,469	147,075
C. Earnings, Before Income Taxes	309,930	176,611	407,429	288,453	418,906
D. Fixed Charges (a)	304,451	308,323	314,973	315,274	319,197
E. Earnings Before Income Taxes and Fixed Charges	614,381	484,934	722,402	603,727	738,103
F. Allowance for Funds Used During Construction	9,706	7,355	9,050	9,079	16,232
G. Earnings Before Income Taxes and Fixed Charges without AFC	$604,675	$477,579	$713,352	$594,648	$721,871
Preferred Dividend Factor:					
H. Preferred Dividend Requirements	$ 37,397	$ 38,281	$ 39,596	$ 33,673	$ 31,857
I. Ratio of Pre-Tax Income to Net Income (C / A)	1.69	1.60	1.64	1.63	1.54
J. Preferred Dividend Factor (H x I)	$ 63,201	$ 61,250	$ 64,937	$ 54,887	$ 49,060
K. Fixed Charges as above (D)	304,451	308,323	314,973	315,274	319,197
L. Fixed Charges and Preferred Dividends Combined	$367,652	$369,573	$379,910	$370,161	[illegible]68,257
M. Ratio of Earnings to Fixed Charges (E / D)	2.02	1.57	2.29	1.91	[illegible].31
N. Ratio of Earnings to Fixed Charges without AFC (G / D)	1.99	1.55	2.26	1.89	[illegible]26
O. Ratio of Earnings to Fixed Charges and Preferred Dividends Combined (E / L)	1.67	1.31	1.90	1.63	[illegible]

(a) Includes a portion of rentals deemed representative of the interest factor: $26,[illegible] for 1997, $26,600 for 1996, $27,312 for 1995, $29,396 for 1994 and $27,821 for 1993.

EXHIBIT 21

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

SUBSIDIARIES OF THE REGISTRANT

Name of Company	State of Organization
Opinac North America, Inc. (Note 1)	Delaware
NM Uranium, Inc.	Texas
EMCO-TECH, Inc. (Note 2)	New York
NM Holdings, Inc. (Note 3)	New York
Moreau Manufacturing Corporation	New York
Beebee Island Corporation	New York
NM Receivables Corp.	New York

NOTE 1: At December 31, 1997, Opinac North America, Inc. owns Opinac Energy Corporation and Plum Street Enterprises, Inc. Opinac Energy Corporation has a 50 percent interest in CNP, which is incorporated in the Province of Ontario, Canada. CNP owns Cowley Ridge Partnership (an Alberta, Canada general partnership) and Canadian Niagara Wind Power Company, Inc. (incorporated in the Province of Alberta, Canada). Plum Street Enterprises, Inc., ("Plum Street") an unregulated company, is incorporated in the State of Delaware. Plum Street owns Plum Street Energy Marketing, Inc. (incorporated in the State of Delaware), Global Energy Enterprises India Private Limited, 90% of Dolphin Investments International, Inc. (a corporation organized and existing under the laws of Nevis, West Indies, which owns 45% of Atlantis Energie Systems AG (a corporation organized and existing under the laws of the Federal Republic of Germany)), 25% of Telergy Joint Venture and 26% of Direct Global Power, Inc.

NOTE 2: EMCO-TECH, Inc. is inactive at December 31, 1997.

NOTE 3: At December 31, 1997, NM Holdings, Inc. owns Salmon Shores, Inc., Moreau Park, Inc., Riverview, Inc., Hudson Pointe, Inc., Upper Hudson Development, Inc., Land Management & Development, Inc., OPropco, Inc. and LandWest, Inc.

EXHIBIT 23

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 33-36189, 33-42771 and 333-13781) and to the incorporation by reference in the Prospectus constituting part of the Registration Statement on Form S-3 (Nos. 33-50703, 33-51073, 33-54827, 33-55546 and 333-49541) and in the Prospectus/Proxy Statement constituting part of the Registration Statement on Form S-4 (No. 333-49769) of Niagara Mohawk Power Corporation of our report dated March 26, 1998, except Note 2 (third paragraph) and Note 15, as to which the date is May 29, 1998 appearing in the Company's Form 10-K/A, Amendment No. 2, dated May 29, 1998. We also consent to the incorporation by reference of our report on the Financial Statement Schedule, which appears in the Form 10-K.

Price Waterhouse LLP
PRICE WATERHOUSE LLP

Syracuse, New York
May 29, 1998

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NIAGARA MOHAWK POWER CORPORATION
(Registrant)

Date: May 29, 1998

Steven W. Tasker
Vice President-Controller
and Principal Accounting
Officer