ANDERSEN

North Carolina Electric Membership Corporation

Financial Statements
As of December 31, 2001, 2000 and 1999
Together with Report of Independent Public Accountants

ANDERSEN

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of
North Carolina Electric Membership Corporation:

We have audited the accompanying balance sheets of **NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION**, a North Carolina corporation, as of December 31, 2001 and 2000, and the related statements of operations and members' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North Carolina Electric Membership Corporation as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

In accordance with *Government Auditing Standards*, we have also issued a report dated February 8, 2002, on our consideration of North Carolina Electric Membership Corporation's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations and contracts. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audits.

ARTHUR ANDERSEN LLP

Raleigh, North Carolina
February 8, 2002

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

BALANCE SHEETS — DECEMBER 31, 2001 AND 2000

(in thousands)

ASSETS	2001	2000
ELECTRIC PLANT:		
In-service	$1,437,108	$1,434,279
Accumulated depreciation	(648,016)	(617,537)
	789,092	816,742
Nuclear fuel, at amortized cost	29,968	34,416
Construction work-in-process	2,977	4,591
	822,037	855,749
OTHER ASSETS AND INVESTMENTS:		
Long-term investments	32,002	82,191
Noncurrent receivables	13,207	14,952
Investments in associated organizations	7,466	7,438
Special deposits	24,886	32,178
Decommissioning fund	57,252	56,180
	134,813	192,939
CURRENT ASSETS:		
Cash and cash equivalents	15,668	14,189
Short-term investments	10,727	14,264
Accounts receivable	103,608	120,857
Accounts receivable – affiliated companies, net	11,494	6,118
Interest receivable	1,035	1,155
Other current assets	532	147
	143,064	156,730
DEFERRED CHARGES:		
Regulatory asset (Note 1)	26,824	3,284
Deferred loss on debt extinguishment (Note 6)	17,463	18,835
Debt issuance costs	7,606	8,084
Preliminary project costs	9,418	9,418
Other	1,839	2,164
	63,150	41,785
	$1,163,064	$1,247,203

MEMBERS' EQUITY AND LIABILITIES	2001	2000
MEMBERS' EQUITY:		
Membership fees	$ 1	$ 1
Patronage capital	22,112	22,112
Net unrealized gain (loss) on available-for-sale securities	290	(89)
	22,403	22,024
LONG-TERM DEBT	983,737	1,024,194
CURRENT LIABILITIES:		
Current maturities of long-term debt	40,454	47,482
Accounts payable	40,423	62,868
Accrued interest	174	15,838
Other accrued expenses	11,855	11,560
	92,906	137,748
DEFERRED CREDITS AND OTHER LIABILITIES:		
Reserve for decommissioning	57,252	56,180
Accrued Department of Energy assessment	4,057	4,548
Other noncurrent liabilities	2,709	2,509
	64,018	63,237
COMMITMENTS AND CONTINGENCIES (Notes 7, 8, 9, 10 and 11)	$1,163,064	$1,247,203

The accompanying notes to financial statements are an integral part of these balance sheets.

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

STATEMENTS OF OPERATIONS AND MEMBERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999

(in thousands)

	2001	2000	1999
OPERATING REVENUES	**$659,818**	$664,894	$635,772
OPERATING EXPENSES:			
Fuel and purchased power	**422,790**	428,593	409,451
Other production expenses	**105,942**	105,162	100,489
Depreciation and amortization	**36,226**	36,676	36,036
Administrative and general	**21,375**	20,510	17,700
General taxes	**11,648**	12,061	12,262
	597,981	603,002	575,938
OPERATING MARGIN	**61,837**	61,892	59,834
OTHER INCOME (EXPENSE):			
Interest and dividend income	**5,859**	6,989	7,909
Other	**(126)**	1,421	3,550
	5,733	8,410	11,459
INTEREST CHARGES:			
Interest expense	**65,252**	68,133	69,064
Debt fees and expenses	**2,318**	2,169	2,229
	67,570	70,302	71,293
NET MARGIN	**0**	0	0
CHANGE IN NET UNREALIZED GAIN (LOSS) ON AVAILABLE-FOR-SALE SECURITIES	**379**	9,951	(10,495)
COMPREHENSIVE INCOME (LOSS)	**379**	9,951	(10,495)
MEMBERS' EQUITY, beginning of year	**22,024**	12,073	22,568
MEMBERS' EQUITY, end of year	**$ 22,403**	$ 22,024	$ 12,073

The accompanying notes to financial statements are an integral part of these statements.

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(in thousands)

	2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net margin	$ 0	$ 0	$ 0
Adjustments to reconcile net margin to net cash and cash equivalents provided by operating activities:			
Depreciation and amortization	40,138	40,382	38,461
Amortization of nuclear fuel	14,626	14,577	15,273
Amortization of regulatory liability	0	(19,180)	(17,211)
Amortization of deferred revenues	0	0	(6,234)
Interest on decommissioning fund	1,072	4,513	3,684
Deferred charges	(25,518)	(2,559)	(959)
Other noncurrent assets and liabilities	1,945	(4,356)	(3,248)
Changes in other operating assets and liabilities:			
Accounts receivable	11,873	(23,280)	(12,207)
Interest receivable	120	(145)	220
Accounts payable	(22,445)	16,035	313
Accrued interest	(15,664)	(1,283)	16,014
Other	(88)	(197)	298
Net cash and cash equivalents provided by operating activities	6,059	24,507	34,404
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to electric plant	(17,140)	(22,414)	(16,836)
Increase in decommissioning fund	(1,072)	(4,513)	(3,684)
Decrease in long-term investments	51,061	9,171	30,000
Decrease in deferred revenue fund	0	0	6,234
(Increase) decrease in short-term investments	3,044	(1,857)	4,469
Other, net	7,013	8,193	(3,315)
Net cash and cash equivalents provided by (used in) investing activities	42,906	(11,420)	16,868
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments of long-term debt	(47,486)	(35,786)	(29,103)
Extinguishment of long-term debt	0	(108,150)	0
Proceeds from issuance of long-term debt	0	104,370	0
Net cash and cash equivalents used in financing activities	(47,486)	(39,566)	(29,103)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,479	(26,479)	22,169
CASH AND CASH EQUIVALENTS, beginning of year	14,189	40,668	18,499
CASH AND CASH EQUIVALENTS, end of year	$15,668	$ 14,189	$40,668
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid during the year for:			
Interest	$80,699	$ 69,247	$52,884
Income taxes	0	0	0

The accompanying notes to financial statements are an integral part of these statements.

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

North Carolina Electric Membership Corporation (the Company) is a member-owned cooperative of 26 electric membership cooperatives (the members) in North Carolina. The Company was formed in 1949 to develop itself as a full-requirements supplier, providing power generation, wholesale electric service and transmission to its members, who in turn service more than 800,000 homes, farms and businesses in North Carolina. The Company follows accounting principles generally accepted in the United States and the practices prescribed in the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC) as modified and adopted by the Rural Utilities Service (RUS).

Electric Plant

Electric plant is stated at original cost, which is the cost of the plant when placed into service, plus the cost of subsequent additions and includes engineering and other indirect construction costs. The cost of renewals and betterments of property is capitalized. The cost of maintenance and repairs and replacements and renewals of items determined to be less than units of property is charged to expense when incurred. At the time properties are disposed of, the original cost plus the cost of removal less salvage of such property, is charged to accumulated depreciation, except in certain cases of properties sold as entireties where profit or loss is recognized.

Depreciation

Depreciation is computed using the straight-line method over the estimated service lives of the property as follows:

	Estimated Lives
Catawba Nuclear Station	40 years
Diesel generation equipment	30 years
Load management equipment	15 years
Building and improvements	35 years
Furniture and fixtures	5-10 years
Computers and telecommunications equipment	3-10 years
Automobiles	4 years

The depreciation rate for the Catawba Nuclear Station (Note 2) has historically included a component to provide for the expected cost of decommissioning the nuclear facility. Based on projected returns from the external trust fund and projected future funding, no such provision was recorded in 1999, 2000 or 2001. In compliance with a Nuclear Regulatory Commission (NRC) regulation, amounts recovered through rates for estimated decommissioning costs (plus interest thereon) are maintained in a separate external trust fund. The provision for expected decommissioning costs, if any, is charged to operations with an offsetting credit to the reserve for decommissioning. Investment earnings generated from the external trust fund designated for decommissioning are maintained in the decommissioning fund with a corresponding increase to the reserve for decommissioning.

The estimate of the expected cost for decommissioning is adjusted periodically to reflect changing price levels and technology. Using a 1999 site study of expected decommissioning costs, including the costs of decontamination, dismantling and site restoration, the Company estimates its portion of such costs to be approximately $543,745,000. The estimate assumes a future annual escalation rate of 3.0% in decommissioning costs and an average investment earnings rate of 6.5%. The decommissioning cost estimates are based on the plant location and cost characteristics for Catawba and assume prompt dismantlement and removal of the plant from service. The actual decommissioning costs are expected to vary from the above estimates because of changes in assumed dates of decommissioning, changes in regulatory requirements, changes in technology and changes in costs of labor, materials and equipment.

In 1996, the Company determined that the decommissioning liability was overstated based upon the revised estimate of ultimate decommissioning costs. As a result, a regulatory liability of $73,000,000 was reported for amounts to be refunded to members. A similar amount was transferred from the decommissioning fund to long-term investments. In 1998, the Company determined that the decommissioning liability remained overstated in the amount of $20,907,000. An additional regulatory liability was created and a similar amount was transferred from the decommissioning fund to long-term investments. This regulatory liability was amortized through 1999, based on each member's KW and KWH billing determinants for the applicable year. Total amortization of this regulatory liability was $8,579,000 in 1999.

Regulatory Assets and Liabilities

The Company currently complies with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended by SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and, accordingly, has recorded regulatory assets and liabilities related to its operations. This statement requires that regulatory assets be probable of future recovery at each balance sheet date. If recovery of the regulatory assets becomes unlikely or uncertain, these accounting standards may no longer apply. The Company periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its regulatory assets are probable of future recovery in the near term.

The Company incurred significant purchased power costs in excess of budgeted amounts during 2001. The Board of Directors determined that these costs would be collected through increased rates in 2002. Accordingly, the Company established a regulatory asset of $24,313,000 which will be amortized over 2002.

The Company has provided funding to support cooperative efforts in the northeastern United States. The Company established a regulatory asset for these amounts which totaled $2,511,000 and $3,284,000 at December 31, 2001 and 2000, respectively. These assets are being amortized on a straight-line basis over a period not to exceed five years. Total amortization of this regulatory asset was $773,000 in 2001 and $557,000 in 2000

Nuclear Fuel

The cost of nuclear fuel, including a provision for the estimated cost of permanent storage of spent fuel, is being amortized based on core burn-up and amounted to $14,626,000 in 2001, $14,577,000 in 2000 and $15,273,000 in 1999. Final disposition of the spent fuel may require future adjustments to fuel expense. Pending ultimate disposition, sufficient storage capacity for spent fuel is available through 2008. The accumulated amortization is $85,119,000 and $70,009,000 at December 31, 2001 and 2000.

Derivative Accounting

The Company adopted the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (the Statement), as amended, beginning January 1, 2001. SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. The Statement requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Substantially all of the Company's bulk power purchases and sales meet the definition of a derivative under SFAS No. 133. However, these transactions also meet the normal purchase and sale exception under the Statement and therefore do not need to be accounted for as derivatives.

In addition, the Company began using derivative instruments during 2001 to manage the risks associated with the short-term (less than 90 days) impact of fluctuating natural gas fuel prices on purchased power contracts. These derivatives are carried at their fair market value as determined by broker quotes and are recorded as derivative assets of $26,000 in other current assets and derivative liabilities of $545,000 in other accrued expenses in the accompanying balance sheets at December 31, 2001. As these derivatives are designated as cash flow hedges, certain gains or losses are deferred as a component of members' equity and will be recognized concurrently with the hedged purchased power costs.

Revenue Deferral Plan

In 1991, the Company established, and the RUS approved, a revenue deferral plan. The plan provided for a predetermined increment to be included in rates charged to members during 1991 through 1995. Revenues collected through the revenue deferral plan were deferred and were utilized to reduce member revenue requirements in 1996 through 1999 as authorized by the Board of Directors. The deferred revenues were allocated to members based on their KW and KWH billing determinants for the applicable year. The cash equivalent of all deferred revenues was segregated into the deferred revenue fund and remained in such fund until it was used to reduce member revenue requirements. The deferred revenue balance was fully amortized at December 31, 1999. Deferred revenue amortization reduced member revenue requirements by $6,234,000 in 1999.

Membership Fees and Patronage Capital

The Company is organized and operates as a cooperative. Its cooperative members paid a total of $700 in membership fees.

Patronage capital is the net margin retained by the Company which is allocated to members based upon their respective purchases of power from the Company.

Income Taxes

The Company is a not-for-profit membership corporation exempt from federal income taxes. In management's opinion, based on the applicable statutes, the Company is not subject to state income taxes.

For the years 1984 and prior, the Company claimed tax-exempt status under Section 501(c)(12) of the Internal Revenue Code of 1954 (the Code), as amended. In 1985, the Company reported as a taxable entity as a result of income received from Duke Power Company (Duke) under a capacity and energy sell-back agreement applicable to Catawba Units No. 1 and 2. As a taxable electric cooperative, the Company annually allocated its income and deductions between member and nonmember activities. Any member taxable income was offset with a patronage exclusion.

In 1999, the Company reapplied for tax-exempt status under Section 501(c)(12) of the Code. The application was approved by the Internal Revenue Service retroactively effective as of January 1, 1996. The impact of this event resulted in the elimination of the accumulated deferred federal income tax liability of $110,453,000 and related noncurrent receivables from members of $12,438,000. In addition, a regulatory asset of $59,467,000, related to the Duke Settlement (Note 9), was eliminated at the same time as authorized by the Board of Directors. As a result of these events, the Company established a net regulatory liability of $38,548,000 to be amortized through 2000. Total amortization of this regulatory liability was $19,180,000 in 2000 and $8,632,000 in 1999. The remaining net balance of $10,736,000 as of December 31, 2000, was returned to members or will be collected from members, based on each member's contribution to the total balance. Accordingly, $14,586,000 of the regulatory liability balance at December 31, 2000, was returned to members in 2001. The remaining balance due from members was $1,723,000 and $3,850,000 at December 31, 2001 and 2000, respectively.

Deferred Charges

Deferred charges, other than preliminary project costs (Note 9), are amortized using the straight-line method over the following estimated periods:

	Estimated Periods
Regulatory asset	1-5 years
Deferred loss on debt extinguishment (Note 6)	17–24 years
Debt issuance costs	24–30 years
Other	5 years

Cash and Cash Equivalents

The Company considers all temporary cash investments purchased with an original maturity of three months or less to be cash equivalents.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications have been made to the prior-year financial statements to conform to the current-year presentation.

New Accounting Pronouncements

The Company is required to adopt the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations" and SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" beginning January 1, 2003 and January 1, 2002, respectively. SFAS No. 143 establishes accounting and reporting standards for the way companies recognize and measure retirement obligations that result from the operation of a long-lived asset. The Statement requires that the fair value of asset retirement obligations be recorded in the balance sheet at the time the liability is incurred which, in many cases, will be when the asset is placed in service. The cost associated with recognizing this obligation is capitalized into the cost of the related long-lived asset. The Company has not yet determined the impact that SFAS No. 143 will have on its financial statements.

SFAS No. 144 established new accounting standards for the impairment of long-lived assets. Management does not believe SFAS No. 144 will have a material impact on its financial statements.

2. JOINTLY OWNED ELECTRIC PLANT AND RELATED AGREEMENTS

On February 6, 1981, the Company entered into (a) the Catawba Nuclear Station Purchase, Construction and Ownership agreement with Duke, together with (b) an Operating and Fuel Agreement and (c) an Interconnection Agreement (the Contracts). Contracts (a) and (b) basically provide for the purchase by the Company of a 56.25% undivided interest in Unit No. 1 of the Catawba Nuclear Station together with a 28.125% interest in the support facilities, and for a sharing of direct construction and operating costs in relation to the respective ownership share of the parties. The Company's total investment in jointly owned facilities amounted to $1,355,078,000 and $1,351,071,000 as of December 31, 2001 and 2000, including capitalized interest expense, net of related investment income.

The cost of power purchased from Duke, as well as power purchased by the Company for its members from Carolina Power & Light Company (CP&L), Virginia Electric and Power Company (VEPCO) and American Electric Power Company (AEP) has been recorded as purchased power on the accompanying statements of operations and patronage capital.

3. FAIR VALUE OF FINANCIAL INSTRUMENTS

A detail of the estimated fair values of the Company's financial instruments as of December 31, 2001 and 2000, is as follows (in thousands):

	2001		2000	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Cash and cash equivalents	**$ 15,668**	**$ 15,668**	$ 14,189	$ 14,189
Short-term investments	**10,727**	**10,727**	14,264	14,264
Long-term investments	**32,002**	**32,002**	82,191	82,191
Special deposits	**24,886**	**24,886**	32,178	32,178
Decommissioning fund	**57,252**	**57,032**	56,180	59,102
Long-term debt	**1,024,191**	**1,098,157**	1,071,676	1,108,601

For cash and cash equivalents, the carrying amount approximates fair value due to the short maturity of those instruments. The carrying amount of the decommissioning fund is determined based on the requirements of the related obligation. The special deposits fund balance is contractually determined to meet certain funding requirements. The fair value of the Company's long-term debt is estimated by management based on the current rates offered to the Company for debt of similar maturities.

The Company's investments may be classified as available-for-sale, trading or held-to-maturity. Available-for-sale securities are carried at market value with unrealized gains and losses added to or deducted from equity. Trading securities are also carried at market value with unrealized gains and losses charged to income. Held-to-maturity securities are carried at amortized cost. All realized and unrealized gains and losses are determined using the specific identification method. As of December 31, 2001 and 2000, $57,252,000 and $56,180,000, respectively, of the decommissioning fund has been classified as held-to-maturity. All other investments are classified as available-for-sale.

The amortized cost, gross unrealized holding gains, gross unrealized losses and fair value of available-for-sale and held-to-maturity securities by major security type at December 31, 2001 and 2000, were as follows (in thousands):

December 31	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Estimated Fair Value
2001:				
Available-for-sale securities:				
U.S. Government and agency securities	$ 23,324	$ 259	$ (123)	$ 23,460
Corporate bonds	28,001	616	(79)	28,538
Equity investments	0	0	0	0
Other	31,668	169	(552)	31,285
	$ 82,993	$1,044	$ (754)	$ 83,283
Held-to-maturity securities:				
U.S. Government and agency securities	$ 7,787	$ 41	$ (46)	$ 7,782
Equity investments	17,781	187	(156)	17,812
Demand notes	24,327	2,789	(3,024)	24,092
Other	7,357	7	(18)	7,346
	$ 57,252	$3,024	$(3,244)	$ 57,032
2000:				
Available-for-sale securities:				
U.S. Government and agency securities	$ 19,064	$ 324	$ (176)	$ 19,212
Corporate bonds	30,959	143	0	31,102
Equity investments	7,200	0	(385)	6,815
Other	85,688	34	(29)	85,693
	$142,911	$ 501	$ (590)	$142,822
Held-to-maturity securities:				
U.S. Government and agency securities	$ 15,243	$ 0	$ (789)	$ 14,454
Equity investments	12,963	0	(398)	12,565
Demand notes	23,348	4,098	0	27,446
Other	4,626	11	0	4,637
	$ 56,180	$4,109	$(1,187)	$ 59,102

Proceeds from the sale of marketable securities were $393,085,000, $181,255,000 and $155,722,000 in 2001, 2000 and 1999, respectively. Related net realized gains included in income were $141,000, $1,475,000 and $3,493,000 in 2001, 2000 and 1999, respectively.

4. INVESTMENTS IN ASSOCIATED ORGANIZATIONS

Investments in associated organizations are stated at cost at December 31, 2001 and 2000, and were as follows (in thousands):

	2001	2000
TSE Services Inc. preferred stock	**$2,000**	$2,000
National Rural Utilities Cooperative Finance Corporation:		
Subordinated Term Certificate	**4,970**	4,970
Capital Term Certificates	**318**	319
Patronage capital certificates	**117**	116
Other	**1**	1
Other investments	**60**	32
	$7,466	$7,438

The Company purchased cumulative preferred stock in TSE Services Inc., a related party (Note 11), with a liquidation preference of $2,000,000.

The Subordinated Term Certificate bears interest at 6.75% per annum. The Capital Term Certificates bear interest at 3% to 5% per annum. These certificates are required to be maintained under debt agreements with the National Rural Utilities Cooperative Finance Corporation (NRUCFC) in an amount at least equal to 5% of the original debt issued or guaranteed by NRUCFC until maturity of the related debt instruments. These investments in associated organizations are similar to compensating bank balances and are necessary in order to maintain current financing arrangements.

5. SPECIAL DEPOSITS

Special deposits consist of debt service reserve funds for pollution control bonds as required by the Company's bond agreements and the Company's agreements with Duke. Debt service reserve funds totaled $8,886,000 and $8,860,000 at December 31, 2001 and 2000, respectively.

In 1994, under the terms of its Catawba ownership agreements with Duke as discussed in Note 2, the Company entered into an Amended Depository Agreement with Duke under which the Company was required to establish a Special Reserve Fund depository account in an amount equal to the greater of $750,000 or one percent of the Company's estimated payments to Duke under the terms of the Interconnection Agreement plus one-sixth of the Company's estimated payments to Duke under terms of the Operating and Fuel Agreement during the current fiscal year. The depository account totaled $18,504,000 and $23,269,000 as of December 31, 2001 and 2000, respectively.

6. LONG-TERM DEBT

Long-term debt consists of mortgage notes payable to the United States of America acting through the Federal Financing Bank (FFB) and the RUS, Pollution Control Revenue Bonds and promissory notes to NRUCFC. Substantially all assets of the Company are pledged as collateral for the debt. The terms of the mortgages, notes and bonds are as follows (in thousands):

	2001	2000
FFB mortgage and RUS note advances, maturing at various dates through 2018 with fixed interest rates ranging from 5.00% to 8.06% at December 31, 2001 and 2000	**$ 919,159**	$ 966,629
Pollution Control Revenue Bonds, Series 2000, with principal payments due in 2020 through 2024, guaranteed by NRUCFC, three series with interest payable monthly at varying rates (average of 1.9% and 4.60% at December 31, 2001 and 2000, respectively)	**99,400**	99,400
NRUCFC note, interest payable semi-annually at 9.05%, principal payments due in 2020 through 2024	**4,970**	4,970
NRUCFC note advances, interest and principal payable quarterly through June 14, 2023, interest rate of 6.0% and 5.88% at December 31, 2001 and 2000, respectively	**662**	677
	1,024,191	1,071,676
Less - Current maturities	**(40,454)**	(47,482)
	$ 983,737	$1,024,194

In conjunction with a debt refinancing in 1998, the Company financed a premium of $96,192,000 with respect to debt that was not substantially modified. The premium with a remaining balance of $85,576,000 as of December 31, 2001, will be paid and recognized as interest expense over a 17-year period (the remaining life of the debt at the time of refinancing). Additionally, a loss on extinguishments of $21,313,000 was incurred with respect to the debt that was substantially modified. This loss was recorded as a deferred charge to be amortized over the same 17-year period. The refinancing will result in a net economic benefit of approximately $68,647,000 over the term of the modified notes.

In September 2000, the Company refunded the remaining Series 1984 Pollution Control Revenue Bonds with an outstanding principal balance of $108,150,000. In connection with the refunding of the bonds, the Company sold the securities in the corresponding Debt Service Reserve Fund and recognized a gain on the sale of $667,000. In addition, the Company wrote off $997,000 of original debt issuance costs which was recorded as a deferred charge to be amortized over a 24-year period (the remaining life of the debt).

Also, in September 2000, the Company issued Series 2000 Pollution Control Revenue Bonds, guaranteed by NRUCFC, in the amount of $99,400,000. The bonds were issued in three series, with principal payments due in 2020 through 2024. Interest on the bonds is payable monthly at varying rates. In addition, the Company borrowed $4,970,000 from NRUCFC to finance the purchase of a subordinate term certificate with NRUCFC, a requirement for NRUCFC to guarantee the pollution control bonds.

Maturities of the long-term debt described above for the five-year period beginning January 1, 2002, and thereafter, are summarized below (in thousands):

Years	Amount
2002	$ 40,454
2003	42,554
2004	45,112
2005	47,641
Thereafter	848,430
	$1,024,191

The Company also has a $30 million line of credit with NRUCFC which was unused at December 31, 2001 and 2000. The interest rate available under this agreement would be determined at the time an advance is made. This line of credit is perpetual and is subject to withdrawal on a revolving basis as needed.

7. EMPLOYEE BENEFIT PLANS

All employees of the Company participate in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program (the Program), a defined benefit pension plan qualified under Section 401 and tax exempt under Section 501(a) of the Code. In this multiemployer plan, which is available to all member cooperatives of NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer. The Company makes annual contributions to the Program equal to the annual pension expense, except during a period when a moratorium is in effect. Payments to the Program for current period service cost were $1,549,000 in 2001, $1,283,000 in 2000 and $999,000 in 1999.

All employees of the Company are eligible to participate in the NRECA Savings Plan, a defined contribution plan qualified under Section 401(k) and tax exempt under Section 501(a) of the Code. Eligible employees may make contributions to the plan of up to 15% of their salary. The Company matches employee contributions to the plan up to 3% of the employee's salary. Total company contributions to the NRECA Savings Plan were $286,000 in 2001, $268,000 in 2000 and $253,000 in 1999.

8. OTHER POSTEMPLOYMENT AND POSTRETIREMENT BENEFITS

The net postretirement benefit liability recognized by the Company, included in other noncurrent liabilities on the accompanying balance sheets, is summarized as follows (in thousands):

	2001	2000
Retired plan participants	$ 455	$ 477
Active plan participants	1,357	1,196
Unrecognized actuarial gain	493	442
Accumulated postretirement benefit obligation	$2,305	$2,115

Net postretirement benefit cost for 2001 and 2000 is included in administrative and general expenses and consists of the following components (in thousands):

	2001	2000	1999
Service cost - Benefits attributed to service during the period	$141	$123	$170
Interest cost on accumulated postretirement benefit obligation	113	112	118
Amortization of actuarial gain	(22)	(20)	0
Net postretirement benefit cost	$232	$215	$288

The Company has revised certain assumptions related to the computation of the accumulated postretirement benefit obligation, resulting in a net actuarial gain of $493,000. For measurement purposes, a 9.0% annual increase in the cost of covered health care benefits was assumed for 2001, the rate was assumed to decrease gradually to 5.5% in the year 2008 and remain at that level thereafter. Increasing the assumed health care cost trend by one percentage point would increase the accumulated postretirement benefit obligation for 2001 by $49,000. The average discount rate used in determining the accumulated postretirement benefit obligation was 7.25%.

9. COMMITMENTS AND CONTINGENCIES

Duke Power Company Settlement

As discussed in Note 2, the Company and certain other parties (the Catawba buyers) own various undivided interests with Duke in Catawba. As of December 31, 1993, a number of contractual disputes existed between the Catawba buyers and/or the Company and Duke, which were resolved in 1994.

One dispute related to billings rendered to Duke by the Company totaling approximately $162,176,000 for income taxes accrued through December 31, 1993. Duke contested the appropriateness of this amount and, therefore, had not paid any amounts billed through 1993. The other disputes related to differences among the parties on interpretation of certain provisions of the Catawba contracts.

In March 1994, the Company and Duke agreed to a settlement of all outstanding disputes. Under the terms of the settlement, Duke paid the Company $75,017,000. Since the terms of the settlement provide that Duke has no further liability for income taxes, the Company wrote-off the remaining receivable balance of $87,159,000 and recorded a regulatory asset in the amount of $56,654,000, which is net of a reduction in accumulated deferred federal income taxes of $30,505,000. This regulatory asset was being amortized over a 20-year period in accordance with the recovery period established by the Board of Directors. The remaining unamortized asset balance was written off in 1999 in conjunction with the Company's reapplication for tax-exempt status (Note 1).

Department of Energy Assessment

The Energy Policy Act of 1992 gave the Department of Energy (DOE) the authority to assess utilities for the decommissioning of its facilities used for the enrichment of uranium included in nuclear fuel costs. In order to decommission these facilities, the DOE estimates that it would need to charge utilities a total of $150,000,000, adjusted for inflation, annually, for 15 years based on enrichment services to date. Based on preliminary estimates from Duke, the Company recorded its share of the liability. A corresponding asset was recorded as nuclear fuel and is being amortized to nuclear fuel expense over the 15-year assessment period. The estimated remaining liability at December 31, 2001, of $4,057,000 is included in the accompanying balance sheets in deferred credits and other liabilities.

Power Coordination Agreements and Purchased Power Commitments

In 2001, the Company entered into Power Supply Agreements (PSA) with American Electric Power Service Corporation (AEP), Dominion Davidson, Inc. (Dominion) and South Carolina Electric & Gas Company (SCE&G) to supply capacity. AEP will provide 100 MW in 2003 and 150 MW in 2004 through 2012. Dominion will provide 100 MW in 2003, 250 MW in 2004 and 570 MW in 2005 through 2030. SCE&G will provide 250 MW beginning in 2004 and continuing through 2012. These resources will replace resources previously supplied under other contractual arrangements and will be used to serve NCEMC's intermediate needs.

In 1998, the Company negotiated a PSA with CP&L which replaced the Power Coordination Agreement. In addition, the Company negotiated a Network Service Agreement which provides for transmission service under CP&L's open access transmission tariff. The new PSA provides for an annual peak rate for the top blocks which is essentially revenue-neutral. These new agreements became effective January 1, 1999.

Also in 1998, the Company entered into an additional purchased power agreement with CP&L for 800 MW of peaking capacity beginning in 2001. The capacity from this purchase will be used to serve NCEMC's peaking needs in 2002 and 2003 in the Duke and CP&L areas, with options to extend to all or part of the 800 MW for 2004 and 2005. The agreement provides for fixed capacity charges and energy charges capped at a gas-indexed rate.

In 1996, the Company renegotiated the Interconnection Agreement with Duke, the Power Coordination Agreement with CP&L and the power supply contract with VEPCO. The negotiations resulted in varying contract expiration dates with more power supply flexibility at prices more closely related to market conditions.

In 1996, the Company began receiving 200 MW of capacity from AEP to replace requirements previously provided by CP&L. The agreement extends through 2010 and provides for fixed capacity charges and system average energy costs.

Plant Construction Agreement

During the mid-1990s, the Company purchased property, incurred licensing and architect fees and entered into an agreement to build a combined-cycle natural gas-fired electric generating plant. Construction of the plant was scheduled to begin in 1998 Due to changing power supply market conditions, in 1996 the Company decided to delay the construction of the generating plant indefinitely. The Company has capitalized these preliminary project costs of $9,418,000 through December 31, 2001, in the accompanying balance sheets. Prior to year-end, the Company entered into a definitive agreement with Dominion to sell the property for approximately $12,000,000 contingent upon receiving approval from RUS.

10. NUCLEAR INSURANCE

Duke maintains nuclear insurance coverage on its nuclear facilities in three areas; liability coverage, property, decontamination and decommissioning coverage and extended accidental outage coverage to cover increased generating costs and/or replacement power purchases. The Company, along with other joint owners of Catawba, reimburses Duke for certain expenses associated with nuclear insurance premiums paid by Duke.

The Price-Anderson Act provides that nuclear reactor owners insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $9.5 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount for the benefit of the co-owners of Catawba to cover certain worker tort claims. In the event of a nuclear incident involving any commercial nuclear facility in the country involving total public liability in excess of $200 million, a licensee of a nuclear power plant could be assessed a deferred premium of up to $88 million (NCEMC's share is $24.8 million) for certain licensed reactors. It would be payable at a rate not to exceed $10 million (NCEMC's share is $2.8 million) per year per licensed reactor for each incident. If retrospective premiums were to be assessed, the Company will be responsible for its share of any retrospective premiums or other costs incurred by Duke in the event an accident occurs where liabilities exceed insurance coverage.

Duke is a member of Nuclear Electric Insurance Limited (NEIL), which provides $500 million in primary property damage coverage for each of Duke's nuclear facilities. If NEIL's losses ever exceed its reserves, Duke will be liable, on a pro rata basis, for additional assessments of up to $18 million (NCEMC's share is $5.1 million). This amount represents five times Duke's annual premium to NEIL. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba

Duke also purchases insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. NEIL provides excess insurance coverage of $2.25 billion for Catawba. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, Duke will be liable, on a pro rata basis, for additional assessments of up to $18 million (NCEMC's share is $5.1 million). The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba.

Duke participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Catawba is insured for up to approximately $4 million per week, after a 12-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100% for 52 weeks and 80% for the next 110 weeks. If NEIL's losses for this program ever exceed its reserves, Duke will be liable, on a pro rata basis, for additional assessments of up to $15 million (NCEMC's share is $4.2 million). This amount represents five times the annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premiums assessments resulting from the NEIL policies applicable to the joint ownership agreements.

11. RELATED-PARTY TRANSACTIONS

In accordance with a management agreement, the Company provides staff services to the North Carolina Association of Electric Cooperatives, Inc. (NCAEC), the Tarheel Electric Membership Association, Inc. and subsidiary (TEMA), TSE Services Inc. and the CEC Self Insurance Fund, Inc., (CECSIF) which are all related parties. The management agreement provides that charges for these services include a component for general corporate expenses and an assessment for office space and computer equipment. The Company also charges the ElecTel Cooperative Credit Union, a related party, a fee for office space and use of the Company's copy machines. Charges to NCAEC were $3,991,000 in 2001, $4,275,000 in 2000 and $1,758,000 in 1999. Charges to TEMA were $2,236,000 in 2001, $2,240,000 in 2000 and $1,928,000 in 1999. Charges to the CECSIF were $40,000 in 2001, 2000 and 1999. Charges to TSE Services Inc. were $4,821,000 in 2001, $5,427,000 in 2000 and $2,222,000 in 1999.

The Company purchases various services from TSE Services Inc. Expenses related to these services totaled $1,209,000 in 2001, $2,566,000 in 2000 and $628,000 in 1999. The Company also purchases various services from NCAEC. Expenses related to these services totaled $2,134,000 in 2001 and $2,638,000 in 2000.

The Company has accounts receivable net of accounts payable with related parties at December 31, 2001 and 2000, as follows (in thousands). These amounts do not bear interest.

	2001	2000
NCAEC	$ 312	$ 313
TEMA	1,062	778
TSE Services Inc.	10,117	5,024
CECSIF	3	3
	$11,494	$6,118

The Company has designated $27,000,000 for loans to members for economic development and construction of customer-owned generation. At December 31, 2001 and 2000, outstanding loans totaling $13,305,000 and $14,598,000, respectively, have been included in accounts receivable and noncurrent receivables in the accompanying balance sheets. Economic development loans (totaling $12,972,000 and $13,950,000 at December 31, 2001 and 2000, respectively) do not bear interest and have repayment terms of up to seven years with an initial payment deferral of up to four years available under certain circumstances. Customer-owned generation loans (totaling $333,000 and $648,000 at December 31, 2001 and 2000, respectively) accrue interest at fixed and variable rates ranging from 1.9% to 8.3%. The repayment terms for these loans range from 3 to 7 years. The contractual maturities of the economic development loans and customer-owned generation loans described above are as follows:

Years	Amount
2002	$ 1,743
2003	1,910
2004	1,934
2005	1,182
Thereafter	6,536
	$13,305

KPMG

PIEDMONT MUNICIPAL POWER AGENCY

Financial Statements and Schedules

December 31, 2001 and 2000

(With Independent Auditors' Report Thereon)

PIEDMONT MUNICIPAL POWER AGENCY

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Suite 900
55 Beattie Place
Greenville, SC 29601-2106

Independent Auditors' Report

The Board of Directors
Piedmont Municipal Power Agency:

We have audited the accompanying balance sheets of Piedmont Municipal Power Agency (the "Agency") as of December 31, 2001 and 2000, and the related statements of revenues and expenses and changes in retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Agency's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Agency, as of December 31, 2001 and 2000, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 2 to the financial statements, the Agency changed its method of accounting for derivative instruments in 2001.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplementary information included in Schedules 1 and 2 is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

KPMG LLP

March 1, 2002

PIEDMONT MUNICIPAL POWER AGENCY

Balance Sheets

December 31, 2001 and 2000
(Dollars in thousands)

Assets		2001	2000
Utility plant (note 5):			
Electric plant in service	$	554,828	554,492
Nuclear fuel		32,076	37,658
Construction work-in-progress		2,516	1,407
		589,420	593,557
Less accumulated depreciation and amortization		(284,854)	(269,565)
Net utility plant		304,566	323,992
Restricted funds (note 6)		198,270	190,380
Revenue fund assets (note 7):			
Cash		7,125	7,637
Marketable debt securities		236,190	235,722
Accrued interest receivable		3,610	4,050
Due from restricted funds		1,292	1,199
Participant accounts receivable		8,992	10,609
Other accounts receivable		4,792	3,601
Materials and supplies		5,742	5,726
Derivative financial instruments		4,832	—
Total revenue fund assets		272,575	268,544
Other assets:			
Unamortized debt issuance costs		18,666	19,908
Net costs recoverable from future Participant billings (note 8)		418,849	397,481
Costs on advance refundings of debt		162,344	173,400
Other		2,521	2,693
Total other assets		602,380	593,482
	$	1,377,791	1,376,398
Liabilities and Retained Earnings			
Long-term debt (notes 9 and 10)			
Bonds		1,286,404	1,302,429
Unamortized discounts		(47,882)	(50,628)
Unamortized premiums		1,066	1,230
		1,239,588	1,253,031
Restricted fund liabilities:			
Accrued interest payable		50,901	49,446
Reserve for decommissioning (note 11)		39,329	35,419
		90,230	84,865
Revenue fund liabilities - accounts payable (note 7)		12,455	10,299
Retained earnings		35,518	28,203
Commitments and contingencies (notes 14 and 15)			
	$	1,377,791	1,376,398

See accompanying notes to financial statements.

PIEDMONT MUNICIPAL POWER AGENCY

Statements of Revenues and Expenses and Changes in Retained Earnings

Years ended December 31, 2001 and 2000
(Dollars in thousands)

		2001	2000
Operating revenues:			
Sales of electricity to Participants	$	117,548	118,082
Sales of electricity to other utilities		16,208	14,475
Other		1,207	1,204
Total operating revenues		134,963	133,761
Operating expenses:			
Operation and maintenance		22,337	22,311
Nuclear fuel amortization		6,958	6,692
Purchased power (note 4)		24,769	26,875
Transmission		4,709	4,466
Distribution		1,409	1,639
Administrative and general		12,426	11,956
Depreciation		18,656	18,792
Decommissioning		3,910	4,392
Payments in lieu of property taxes		4,385	4,550
Total operating expenses		99,559	101,673
Net operating income		35,404	32,088
Other income (expenses):			
Interest income		26,772	27,848
Net increase in fair value of investments and derivative instruments		4,853	12,196
Interest expense		(69,587)	(73,735)
Amortization expense		(13,402)	(13,566)
Other expense, net		(2,485)	(5,405)
Total other expenses, net		(53,849)	(52,662)
Revenues under expenses before deferred items		(18,445)	(20,574)
Net expenses recoverable from future Participant billings (notes 2 and 8)		21,368	23,409
Revenues over expenses before cumulative effect of a change in accounting principle		2,923	2,835
Cumulative effect of a change in accounting principle (note 2)		4,392	—
Revenues over expenses		7,315	2,835
Retained earnings at beginning of year		28,203	25,368
Retained earnings at end of year	$	35,518	28,203

See accompanying notes to financial statements.

PIEDMONT MUNICIPAL POWER AGENCY

Statements of Cash Flows

Years ended December 31, 2001 and 2000
(Dollars in thousands)

		2001	2000
Cash flows from operating activities:			
Revenues over expenses	$	7,315	2,835
Adjustments to reconcile revenues over expenses to net cash provided by operating activities:			
Depreciation and amortization		39,016	39,050
Cumulative effect of a change in accounting principle		(4,392)	—
Net increase in fair value of investments and derivative instruments		(4,853)	(12,196)
Net expenses recoverable from future Participant billings		(21,368)	(23,409)
Reserve for decommissioning		3,910	4,392
Decrease (increase) in:			
Participant accounts receivable		1,617	(1,741)
Other accounts receivable		(1,191)	(2,426)
Accrued interest receivable		12	(869)
Materials and supplies		(16)	(202)
Increase (decrease) in:			
Accounts payable		2,156	3,264
Accrued interest payable		1,455	1,832
Net cash provided by operating activities		23,661	10,530
Cash flows from investing activities:			
Purchase of investment securities		(1,647,834)	(1,712,993)
Proceeds from sales and maturities of investment securities		1,663,475	1,733,205
Expenditures for electric plant in service		(1,462)	(807)
Expenditures for nuclear fuel		(4,726)	(10,033)
Net cash provided by investing activities		9,453	9,372
Cash flows from financing activities:			
Payment of bond principal		(16,025)	(21,200)
Defeasance losses		1,792	1,833
Other		(142)	—
Net cash used in financing activities		(14,375)	(19,367)
Net increase in cash		18,739	535
Cash at beginning of year (note 7)		7,637	7,102
Cash at end of year (notes 6 and 7)	$	26,376	7,637
Supplemental disclosure of cash flow information:			
Cash paid during the year for interest	$	65,641	69,392
Cash received during the year for investment income	$	25,903	21,397

See accompanying notes to financial statements.

(1) Description of the Entity, Industry Restructuring Developments, and Related Uncertainties

Description of the Entity

Piedmont Municipal Power Agency (Agency) was incorporated in 1979 under the South Carolina Joint Municipal Electric Power and Energy Act. The Act, adopted April 1978, enabled the formation, by South Carolina municipalities and municipal commissions of public works, of a joint agency to plan, finance, develop, own and operate electric generation and transmission facilities. Ten municipal utility systems (Participants) comprise the Agency's membership. The Participants, located in northwestern South Carolina, are the cities of Abbeville, Clinton, Easley, Gaffney, Greer, Laurens, Newberry, Rock Hill, Union and Westminster.

The Agency and Duke Power Company (Duke) are parties to agreements giving the Agency a 25% undivided ownership interest in Catawba Nuclear Station Unit 2 (Project). Duke is the operating owner of the Project. The Agency's Project power output entitlements (approximately 286 MW) come from Catawba Nuclear Station Units 1 and 2; subject to the terms of the "Catawba Reliability Exchange" under which the Agency pays 12.5% of the costs and receives 12.5% of the power output associated with each of these 1,145 MW units. Additionally, the terms of the "McGuire Reliability Exchange" allow transfers of energy between the Agency's resulting entitlements from the Catawba Units and Duke's two nuclear units at McGuire Nuclear Station. The operating licenses for Catawba Unit 1 and Unit 2 expire on December 6, 2024 and February 24, 2026, respectively.

Industry Restructuring Developments and Related Uncertainties

During the 113th General Assembly of the South Carolina legislature (which included calendar years 1999 and 2000) both the South Carolina Senate and House of Representatives considered deregulation legislation. House Bill 3902 was introduced during the 1999 session and Senate Bill 1168 was introduced early in the 2000 session. Neither bill was passed.

As a result of deregulation in California and the problems that have occurred, the Agency does not expect to see any deregulation activity during the current session of the South Carolina legislature (which includes calendar years 2002 and 2003) unless an initiative is passed at the federal level. The Agency will continue to monitor deregulation activity both on the national and state level.

The Agency has developed a strategic plan to help guide it through the potential industry changes that includes periodic reviews of the recoverability of regulatory assets and the impact of such recovery on the Agency's rates. The Agency's management is participating in the deregulation debate, both on the national and state level.

In the event that the electric utility industry is restructured, the Agency and the Participants can expect to have as their major competition the investor owned utilities and rural electric cooperatives presently operating in South Carolina and independent power producers, power marketers and others that may offer retail and wholesale services in South Carolina after restructuring The Participants' present retail electric rates are higher, on average, than the present retail electric rates of the area's investor owned utilities.

(Continued)

The Agency's present charges to the Participants, together with planned withdrawals from the Rate Stabilization Account, are sufficient to recover all of the Agency's current costs of supplying the Participant's bulk power supply. Currently each Participant is able, and under its Power Sales Agreements is required, to set its rates at levels necessary to pay all the costs of its electric utility system, including the Agency's charges for supplying power to the Participants. However, studies by the Agency show that, in a deregulated electric utility industry, anticipated market-based retail rates would be lower than those that the Participants would need to charge in order to pay the Agency's charges and to cover all of the other costs and expenses of their electric utility systems, giving rise to stranded investments of the Agency and the Participants and the need for stranded investment recovery by the Agency and the Participants.

For the Agency and the Participants to be competitive in a deregulated retail electric utility industry, the Agency and the Participants must recover the Agency's substantial stranded investments in the Project. The Agency expects that the methods by which it and the Participants may recover some or all of these stranded investments would come from the legislative initiatives. As a result of the foregoing described uncertainties, including the inability to predict the outcome of the legislative process, no assurance can be given that the Agency and the Participants would be able to recover, in whole or in part, these stranded investments in the event of deregulation of the retail electric utility industry.

(2) Summary of Significant Accounting Policies

Basis of Accounting

The Agency's accounting records are maintained on an accrual basis in conformity with accounting principles generally accepted in the United States of America and substantially in conformity with the Federal Energy Regulatory Commission's Uniform System of Accounts.

The Agency follows the accounting practices set forth in Statement of Financial Accounting Standards No. 71 (SFAS No. 71), *Accounting for the Effects of Certain Types of Regulation*, as amended. This standard requires entities to capitalize or defer certain costs or revenues based on the Agency's ongoing assessment that it is probable that such items will be recovered through future revenues based on the rate-making authority of the Agency's Board of Directors.

The ability of the Agency to continue to meet the criteria to account for its operations pursuant to SFAS No. 71 depends primarily upon the pace of the State of South Carolina in allowing deregulation of the generation portion of the utility industry. SFAS No. 71 requires entities to capitalize or defer certain costs or revenues based on the Agency's ongoing assessment that it is probable that such items will be recovered through future revenues. The criteria require consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized cost.

If the Agency no longer applied SFAS No. 71 due to competition, regulatory changes or other reasons, the Agency would make certain adjustments. These adjustments could include the write-off of all or a portion of its regulatory assets and liabilities. These adjustments also could lead to the evaluation of utility plant, contracts and commitments and the recognition, if necessary, of any losses to reflect market conditions.

The Agency's General Bond Resolution requires that its rate structure be designed to produce revenues sufficient to pay operating, debt service and other specified costs. The Agency's Board, which is comprised of representatives of the Participants, is responsible for reviewing and approving the rate structure. The application of a given rate structure to a given period's electricity sales may produce revenues not intended to pay that period's costs, and conversely, that period's costs may not be intended to be recovered in period revenues. The affected revenues and/or costs are, in such cases, deferred for future recognition. The ultimate recognition of deferred items is correlated with specific future events; primarily payment of debt principal.

Unamortized Debt Issuance Costs

Unamortized debt issuance costs at December 31, 2001 and 2000 of $18,666 and $19,908, respectively, (net of accumulated amortization of $21,556 and $20,171, respectively) are being amortized over the term of the related debt.

Costs on Advance Refundings of Debt

Costs on advance refundings of debt at December 31, 2001 and 2000 of $162,344 and $173,400, respectively, (net of accumulated amortization of $137,409 and $126,352, respectively) have been deferred in accordance with SFAS No. 71 and are being amortized over the term of the debt issued on refunding.

Discounts on Bonds Payable

The discounts on bonds payable at December 31, 2001 and 2000 of $47,882 and $50,628, respectively, (net of accumulated amortization of $42,094 and $39,348, respectively) are being amortized on the bonds outstanding method which approximates the effective interest method.

Premiums on Bonds Payable

The premiums on bonds payable at December 31, 2001 and 2000 of $1,066 and $1,230, respectively, (net of accumulated amortization of $1,288 and $1,124, respectively) are being amortized on the bonds outstanding method which approximates the effective interest method.

Income Taxes

The Agency is recognized as a public utility for federal income tax purposes. As such, gross income of the Agency is excluded from federal income taxes under Internal Revenue Code section 115.

Cash Flows

For purposes of the statements of cash flows, the Agency considers interest-bearing deposits with banks and Duke to be cash.

(Continued)

Marketable Debt Securities

As authorized by the General Bond Resolution, investment securities at December 31, 2001 consist only of direct obligations of the United States government and obligations of United States government agencies. These investments are uninsured and unregistered and are held by the Agency's trustees in the Agency's name.

Marketable debt securities are recorded at fair value. Unrealized holding gains and losses on marketable debt securities are included in income. Interest income is recognized when earned.

Utility Plant

Electric plant in service, including unclassified assets, is stated at cost and is depreciated on a straight-line basis at rates calculated to depreciate the composite assets over their respective estimated useful lives. Depreciation begins when assets are placed into service. The Agency's annual provision for depreciation expressed as a percentage of the average balance of depreciable utility plant was 3.3% for 2001 and 2000.

Materials and Supplies

Materials and supplies inventories are stated at lower of cost or market using the average cost method.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Financial Reporting

Under Governmental Accounting Standards Board (GASB) Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*, the Agency has adopted the option to apply Financial Accounting Standards Board (FASB) statements and interpretations that do not conflict with or contradict GASB pronouncements.

Revenue Recognition

The Agency recognizes revenue on sales when the electricity is provided to and used by the customers.

(Continued)

Recently Issued Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires the Agency to record the fair alue of an asset requirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The Agency is required to adopt SFAS No. 143 on January 1, 2003. The Agency will record a corresponding asset which will be depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Any such adjustments for changes in the estimated future cash flows will also be capitalized and amortized over the remaining life of the asset.

Derivative Financial Instruments

In June 1998 the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Certain Hedging Activities" (SFAS No. 133). In June 2000 the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activity, an Amendment of SFAS 133" (SFAS No. 138). SFAS No. 133 and SFAS No. 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. SFAS No. 133 and SFAS No. 138 are effective for of all fiscal years beginning after June 30, 2000; the Agency adopted SFAS No. 133 and SFAS No. 138 on January 1, 2001. In accordance with the transition provisions of SFAS No. 133, the Agency recorded a cumulative-effect-adjustment of $4,392 in the statement of revenues and expenses to recognize at fair value all derivatives outstanding at that date.

All derivatives are recognized on the balance sheet at their fair value. The Agency has not designated any of its derivatives as hedges. Changes in the fair value of derivative instruments are reported in current-period revenues and expenses.

(Continued)

(Dollars in thousands)

For the year ended December 31, 2000, prior to the adoption of SFAS No. 133, the Agency entered into interest rate swap agreements and forward delivery contracts. For interest rate swaps, the differential to be paid or received is accrued and recognized in other income (expense) and may change as market interest rates change. For forward delivery contracts, the interest to be received is accrued and recognized in interest income. If a swap or forward delivery contract is terminated prior to its maturity, the gain or loss is recognized immediately.

(3) Power Sales Agreements

Catawba Project Power Sales Agreements

The Agency and each Participant are parties to Catawba Project Power Sales Agreements (Sales Agreements). These Sales Agreements oblige the Agency to provide each Participant a share of Project power output and, in turn, each Participant must pay its share of Project costs. Participants make their payments on a "take-or-pay" basis whether or not the Project is operable or operating. Such payments are not subject to reduction or offset and are not conditioned upon performance by the Agency or any given Participant. The Sales Agreements are in effect until the earlier of August 1, 2035, or the completion of payments on the bonds and satisfaction of obligations under the Project agreements.

The Participants' Shares of the Agency's Catawba Project Output are as follows:

City of Abbeville	2.68%
City of Clinton	7.84%
City of Easley	13.24%
City of Gaffney	10.05%
City of Greer	9.34%
City of Laurens	6.49%
City of Newberry	10.47%
City of Rock Hill	28.04%
City of Union	10.01%
City of Westminster	1.84%
	100.00%

Supplemental Power Sales Agreements

The Agency and each Participant are also parties to Supplemental Power Sales Agreements (Supplemental Agreements) under which each Participant has agreed to pay, in exchange for supplemental bulk power supply, its share of supplemental bulk power supply costs. A Participant may terminate its Supplemental Agreement with ten years advance notice.

(Continued)

(4) Project Agreements

Project Agreements between the Agency and Duke consist of the Catawba Nuclear Station Purchase, Construction and Ownership Agreement (the Purchase Agreement), the Catawba Nuclear Station Operating and Fuel Agreement (the Operating Agreement), and the Catawba Nuclear Station Interconnection Agreement (the Interconnection Agreement).

Purchase Agreement

This agreement between the Agency and Duke provides for the purchase of the Catawba Project by the Agency. It also details Duke's responsibilities, as engineer-contractor, for construction, initial fueling, and placing the Catawba Nuclear Station into commercial operation.

Operating Agreement

This agreement, between the Agency and Duke, provides for Duke, as operator for the Agency, to be responsible for the operation, maintenance, and fueling of Catawba and for making of renewals, replacements and capital additions. In addition, the Operating Agreement provides for decommissioning of Catawba at the end of its useful life pursuant to the terms of a decommissioning agreement, separate from the Operating Agreement.

Interconnection Agreement

This agreement, between the Agency and Duke, provides for interconnection of the Agency's ownership share of Catawba Unit 1 with the Duke system. As part of the Interconnection Agreement, the Agency is allowed to exchange capacity and output of four nuclear units. The agreement also provides for sale by the Agency of surplus energy to Duke and third parties. It also makes provision for the purchase of supplemental capacity and energy, transmission services and reserve purchases.

In December 1997, the Agency's Board of Directors voted to issue notice, pursuant to the contract, to cancel the Interconnection Agreement with Duke. The cancellation is effective January 1, 2006.

(Dollars in thousands)

(5) Utility Plant

Original costs of major classes of the Agency's electric plant in service at December 31, 2001 and 2000 are as follows:

		2001	2000
Land	$	336	336
Structures and improvements		157,032	157,032
Reactor plant equipment		248,023	248,023
Turbo generator units		69,270	69,270
Accessory electric equipment		50,623	50,623
Miscellaneous plant equipment		16,757	16,757
Station equipment		5,477	5,477
Transmission equipment		1,242	1,240
Other		1,897	1,883
Unclassified		4,171	3,851
	$	554,828	554,492

Unclassified assets are in service but not yet classified to specific plant accounts.

Nuclear fuel at December 31, 2001 and 2000 of $32,076 and $37,658, respectively, represents costs associated with acquiring and processing reload fuel assemblies as well as the cost of nuclear fuel in the reactor. Nuclear fuel is amortized based on burn rates using a unit of production basis. The Agency regularly writes off fully amortized nuclear fuel costs when fuel batches are replaced during core refueling operations. Fully amortized fuel costs of $10,308 and $9,534 were written off during 2001 and 2000, respectively.

A summary of accumulated depreciation and amortization at December 31, 2001 and 2000 are as follows:

		2001	2000
Accumulated depreciation of electric plant in service	$	266,487	247,847
Accumulated amortization of nuclear fuel		18,367	21,718
	$	284,854	269,565

(Dollars in thousands)

(6) Restricted Funds

The General Bond Resolution, Project agreements, and Agency policies restrict the use of bond proceeds, Agency revenues, and Agency funds on hand. Certain restrictions define the order in which available funds may be used to pay costs; other restrictions require minimum balances or accumulation of balances for specific purposes. At December 31, 2001 and 2000, the Agency was in compliance with all such restrictions and held the following restricted assets:

	2001		2000	
	Fair value	Amortized cost	Fair value	Amortized cost
Debt service - bond principal	$ 19,370	19,370	16,021	16,025
Debt service - bond fixed rate interest	29,550	29,550	30,513	30,518
Debt service - bond retirement	1	1	1	1
Debt service reserve	85,328	83,850	84,601	83,850
Reserve and contingency	8,616	8,385	8,548	8,385
Decommissioning	40,142	39,329	35,536	35,419
Special reserve	15,263	15,000	15,160	15,000
	$ 198,270	195,485	190,380	189,198
Funds are comprised of:				
Marketable debt securities	196,634	193,849	189,079	187,897
Accrued interest receivable	2,928	2,928	2,500	2,500
Due to revenue fund	(1,292)	(1,292)	(1,199)	(1,199)
	$ 198,270	195,485	190,380	189,198

Restricted funds include $19,251 and $0 of cash at December 31, 2001 and 2000, respectively. The cash at December 31, 2001 is uninsured and uncollateralized.

(7) Revenue Fund Assets and Liabilities

Revenue fund assets and liabilities are used in the Agency's day-to-day operations. The assets are allocated for the following purposes:

	2001		2000	
	Fair value	Amortized cost	Fair value	Amortized cost
Working capital	$ 76,283	74,895	65,953	65,402
Derivative financial instruments	4,832	—	—	—
Fuel acquisition	30,503	30,503	28,271	28,271
Rate stabilization	160,957	155,781	174,320	171,118
	$ 272,575	261,179	268,544	264,791

(Continued)

(Dollars in thousands)

The revenue fund includes $7,125 and $7,367 of uninsured and uncollateralized cash at December 31, 2001 and 2000, respectively. Liabilities of $12,455 and $10,299 at December 31, 2001 and 2000, respectively, will be paid out of working capital assets.

(8) Net Expenses Recoverable from Future Participant Billings

As described in notes 1 and 2, rates charged to Participants are structured to systematically provide for debt requirements and operating costs of the Agency. The expenses and revenues excluded from rates are deferred to such periods as they are intended to be included in rates.

Net expenses recoverable from future Participant billings:

		2001	2000	Change
		(Cumulative Totals)		
Items to be recovered in future Participant billings:				
Interest expense	$	331,796	329,373	2,423
Depreciation expense		282,818	265,340	17,478
Amortization of redemption and defeasance losses		138,463	127,264	11,199
Amortization of bond discounts and debt issuance costs		63,526	59,559	3,967
Nuclear fuel expenses		873	873	—
Letter of credit fees		5,649	5,649	—
Other		2,392	2,392	—
	$	825,517	790,450	35,067
Items reducing future Participant billings:				
Investment income	$	(76,528)	(76,528)	—
Increase in fair value of investments and derivative instruments		(14,182)	(4,937)	(9,245)
Rate stabilization (revenue received to reduce future billings to Participants)		(513,888)	(503,107)	(10,781)
Reserve and contingency deposits		(36,751)	(35,425)	(1,326)
	$	(641,349)	(619,997)	(21,352)
Revenues (expenses) recognized:				
Interest, depreciation, amortization expense included in Participant billings for debt principal payments	$	(129,043)	(109,674)	(19,369)
Rate stabilization draws applied to expenses		358,106	331,989	26,117
Reserve and contingency revenue applied to expenses		5,618	4,713	905
Net costs recoverable from future Participant billings	$	418,849	397,481	21,368

(Continued)

The following expenses will be recognized in future periods when rates charged to Participants produce revenues sufficient to retire the debt that funded those costs:

- Interest expense on the Agency's bonds and variable rate demand obligations along with associated letter-of-credit, banking and re-marketing fees (except interest and fees related to Capital Appreciation Bonds) paid from bond proceeds during a defined "Construction Period," (net of income earned on the temporary investment of those bond proceeds);

- Interest expense on Capital Appreciation Bonds accrued but not paid until maturity;

- Amortization of debt issuance expenses, bond discounts, defeasance losses, redemption losses, and organization costs paid from or included in bond proceeds;

- Depreciation on utility plant constructed with bond proceeds and amortization of nuclear fuel acquired with bond proceeds; and

- Certain other project costs paid from bond proceeds.

The Agency has also deferred Participant revenues that, during the Construction Period, were established at levels to cover Project costs not paid from bond proceeds, as well as scheduled deposits to a Rate Stabilization account. The revenue associated with those scheduled deposits and the interest income thereon will be recognized when those funds are drawn upon to pay Project costs. Also, certain settlement revenues and excess revenues in certain funds have been transferred to the Rate Stabilization account and have been deferred for recognition until the time the funds are applied to the payment of Project costs.

Revenues or costs associated with increases or decreases in the fair value of investments have been deferred until such time the securities have matured or are sold.

Additionally, the Agency's General Bond Resolution requires Participant revenues to be established at levels sufficient to provide specified deposits into a Reserve and Contingency fund. Monies in that fund are used for the construction or acquisition of utility plant. The recognition of such revenues is deferred until such time as the depreciation is recorded on the assets constructed or acquired with those monies.

(Continued)

PIEDMONT MUNICIPAL POWER AGENCY

Notes to Financial Statements

December 31, 2001 and 2000

(Dollars in thousands)

(9) Long-term Debt

Long-term debt at December 31, 2001 and 2000 consists of the following:

	2001	2000
1986 Refunding Series Electric Revenue Bonds, payable in 2025 with interest at 5%	$ 33,620	33,620
1986A Refunding Series Electric Revenue Bonds, payable in 2023 and 2024 with interest at 5.75%	103,815	103,815
1988 Capital Appreciation Electric Revenue Bonds, payable annually and from 2010 to 2013 with interest at 7.75%	7,745	7,745
1988A Capital Appreciation Electric Revenue Bonds, payable annually from 2004 to 2015 with interest ranging from 7.3% to 7.65%	4,284	4,284
1991 Refunding Series Electric Revenue Bonds, payable annually from 2005 to 2023 with interest ranging from 4% to 6.85%	213,550	213,550
1991A Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2007 and from 2013 to 2018 with interest ranging from 5% to 6.5%	145,150	146,375
1992 Refunding Series Electric Revenue Bonds, payable annually from 2010 to 2014 with interest at 6.3%	19,940	19,940
1993 Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2025 with interest ranging from 4.9% to 5.6%	77,380	79,795
1996A Refunding Series Electric Revenue Bonds, payable annually from 2013 to 2021 with interest ranging from 6.55% to 6.6%	69,140	69,140
1996B Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2013 with interest ranging from 4.8% to 6.0%	121,790	133,075

(Continued)

PIEDMONT MUNICIPAL POWER AGENCY

Notes to Financial Statements

December 31, 2001 and 2000

(Dollars in thousands)

		2001	2000
1996C Refunding Series Electric Revenue Bonds, payable annually in 2021 to 2022 with variable interest rates (1.55% and 4.75% at December 31, 2001 and 2000, respectively)	$	50,000	50,000
1996D Refunding Series Electric Revenue Bonds, payable annually from 2022 to 2025 with variable interest rates (1.6% and 4.8% at December 31, 2001 and 2000, respectively)		50,000	50,000
1997A Refunding Series Electric Revenue Bonds, payable in 2024 with variable interest rates (1.6% and 5.0% at December 31, 2001 and 2000, respectively)		31,700	31,700
1997B Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2003 and 2016 to 2019 with variable interest rates (1.55% and 4.75% at December 31, 2001 and 2000, respectively)		64,485	65,200
1997C Refunding Series Electric Revenue Bonds, payable annually from 2002 to 2003 and 2016 to 2019 with variable interest rates (1.6% and 5.0% at December 31, 2001 and 2000, respectively)		34,915	35,300
1998A Refunding Series Electric Revenue Bonds, payable annually from 2006 to 2025 with interest ranging from 4.4% to 5.5%		161,380	161,380
1999A Refunding Series Electric Revenue Bonds, payable annually from 2014 to 2016 and 2020 to 2021 with interest at 5.25%		97,510	97,510
Total long-term debt		1,286,404	1,302,429
Less unamortized discount		(47,882)	(50,628)
Plus unamortized premium		1,066	1,230
	$	1,239,588	1,253,031

The bonds are special obligations of the Agency and are secured by future revenue and pledged monies and securities as provided by the bond resolution

(Continued)

(Dollars in thousands)

The bonds generally provide for early redemption beginning ten years after issuance at prices ranging from 100% to 103% of the bond principal amounts.

The Agency has advance refunded certain bond issues as described in note 10.

The following is a summary of total debt service deposit requirements for bonds outstanding at December 31, 2001:

Year		Principal	Interest	Total
2002	$	20,470	67,905	88,375
2003		20,880	67,804	88,684
2004		23,015	66,601	89,616
2005		24,728	65,314	90,042
2006		31,772	63,854	95,626
2007		33,993	61,975	95,968
2008		43,056	60,139	103,195
2009		37,391	65,641	103,032
2010		37,309	65,634	102,943
2011		39,049	63,773	102,822
2012		38,759	61,839	100,598
2013		52,972	49,509	102,481
2014		57,630	46,338	103,968
2015		61,105	41,780	102,885
2016		64,270	38,546	102,816
2017		67,360	35,303	102,663
2018		68,995	31,916	100,911
2019		80,795	28,132	108,927
2020		85,665	23,396	109,061
2021		90,480	18,889	109,369
2022		92,975	14,619	107,594
2023		100,590	9,902	110,492
2024		93,775	4,681	98,456
	$	1,267,034	1,053,490	2,320,524

The debt service deposit requirements for principal differ from total long-term debt outstanding at December 31, 2001, because the principal payment of $19,370 which is due January 1, 2002, was deposited during 2001. All principal payments are due on January 1 of the year subsequent to the deposit requirement.

(10) In-Substance Debt Defeasance

In prior years, the Agency defeased in-substance certain Electric Revenue Bonds by placing the proceeds of new bonds in an irrevocable trust fund to provide for future debt service payments on the old debt. Accordingly, the trust account asset and the liability for the defeased bonds are not included in the accompanying financial statements. On December 31, 2001, $302,855 of the bonds are considered defeased in-substance.

(11) Reserve for Decommissioning

The Agency is in compliance with Nuclear Regulatory Commission requirements for funding future decommissioning costs. Since 1985, the Agency has been making regular deposits to segregated decommissioning accounts. The Agency accrues its decommissioning liability over the life of the Project based on its required funding and interest earnings on the decommissioning funds. Deposits pertaining to contaminated portions of the Project are held by a Trustee. The Agency has custody of funds set aside to decommission non-contaminated portions of the Project. The Agency's share of the total decommissioning costs, based on decommissioning studies completed in 1999, is estimated to be $109,500 (in 1999 dollars). This estimate presumes the Catawba Nuclear Station will be decommissioned as soon as possible following the expiration of its operating licenses in 2024 and 2026.

(12) Employee Benefit Plans

The Agency maintains a defined contribution money purchase plan in compliance with Section 401(a) of the Internal Revenue Code. On behalf of all full-time employees, the Agency contributes 10% of base salary into the money purchase plan. Agency contributions totaled $139 and $100 in 2001 and 2000, respectively. Employee contributions may also be made to the Plan, providing combined employer and employee annual contributions do not exceed 25% of eligible employee compensation, or $30, whichever is less.

The Agency also maintains a deferred compensation plan under Section 457 of the Internal Revenue Code. From time to time, on behalf of selected employees, the Agency contributes to the deferred compensation plan. Employee contributions may also be made to the deferred compensation plan providing combined employer and employee annual contributions do not exceed certain limitations.

Assets of the money purchase plan and deferred compensation plan are held by Prudential Financial, administrator and trustee, for the Agency for the exclusive benefit of the employees.

(Continued)

(13) Disclosures Regarding Fair Value of Financial Instruments

Statement of Financial Accounting Standards No. 107 (SFAS No. 107), *Disclosure About Fair Value of Financial Instruments*, requires disclosure of fair value information about financial instruments whether or not recognized in the balance sheet, for which it is practicable to estimate fair value. Fair value estimates are made as of a specific point in time based on the characteristics of the financial instruments and the relevant market information. Where available, quoted market prices are used. In other cases, fair values are based on estimates using present value or other valuation techniques. These techniques involve uncertainties and are significantly affected by the assumptions used and the judgments made regarding risk characteristics of various financial instruments, discount rates, prepayments, estimates of future cash flows, future expected loss experience and other factors. Changes in assumptions could significantly affect these estimates. Derived fair value estimates cannot be substantiated by comparison to independent markets and, in many cases, may or may not be realized in an immediate sale of the instrument.

Under SFAS No. 107, fair value estimates are based on existing financial instruments without attempting to estimate the value of anticipated future business and the value of the assets and liabilities that are not financial instruments. Accordingly, the aggregate fair value amounts presented do not represent the underlying value of the Agency.

The following describes the methods and assumptions used by the Agency in determining carrying value and estimated fair value of financial instruments:

(a) Cash

Carrying value equals estimated fair value.

(b) Marketable Debt Securities

Estimated fair value, which is the carrying value, of all marketable debt securities is derived from quoted market prices.

(c) Derivative Financial Instruments

Estimated fair value of derivative financial instruments is derived from current market pricing models.

(d) Participant Accounts Receivable, and Other Accounts Receivable

Carrying amount approximates fair value due to the short-term nature of these instruments.

(e) Long-term Debt

Carrying value of long-term debt coupon securities includes par, less unaccreted discounts, plus unamortized premiums, plus accrued interest payable. Carrying value also includes Capital Appreciation Term Bonds valued at original price plus accreted discount.

Estimated fair value of all long-term debt securities is derived from quoted market prices and includes accrued interest.

(Continued)

(Dollars in thousands)

The estimated fair values of the Agency's long-term debt with carrying values different from their estimated fair values at December 31, 2001 and 2000 are as follows:

		2001		2000	
		Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
1986	Electric Revenue Refunding Bonds	$ 27,536	30,729	27,235	29,628
1986A	Electric Revenue Refunding Bonds	95,573	103,935	95,051	100,952
1988	Electric Revenue Refunding Bonds	22,070	42,342	20,454	39,465
1988A	Electric Revenue Refunding Bonds	11,310	20,724	10,502	19,201
1991	Electric Revenue Refunding Bonds	205,403	227,619	204,600	230,539
1991A	Electric Revenue Refunding Bonds	145,510	147,695	146,409	161,329
1992	Electric Revenue Refunding Bonds	20,440	21,770	20,425	21,721
1993	Electric Revenue Refunding Bonds	78,143	80,378	80,546	85,196
1996A	Electric Revenue Refunding Bonds	71,193	71,853	71,177	71,513
1996B	Electric Revenue Refunding Bonds	123,887	127,756	135,355	142,344
1996C/D	Electric Revenue Refunding Bonds	100,108	100,108	100,361	100,361
1997A	Electric Revenue Refunding Bonds	31,735	31,735	31,816	31,816
1997B/C	Electric Revenue Refunding Bonds	99,508	99,508	100,864	100,864
1998A	Electric Revenue Refunding Bonds	160,612	160,730	160,385	160,045
1999A	Electric Revenue Refunding Bonds	97,461	93,921	97,297	93,955
		$ 1,290,489	1,360,803	1,302,477	1,388,929

(14) Nuclear Insurance

Nuclear Insurance. Duke Energy owns and operates the McGuire and Oconee Nuclear Stations with two and three nuclear reactors, respectively, and operates and has a partial ownership interest in the Catawba Nuclear Station with two nuclear reactors. Nuclear insurance coverage is maintained in three program areas: liability coverage; property, decontamination and decommissioning coverage; and business interruption and/or extra expense coverage. Certain expenses associated with nuclear insurance premiums paid by Duke Energy are reimbursed by the other joint owners of the Catawba Nuclear Station.

Pursuant to the Price-Anderson Act, Duke Energy is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $9.5 billion.

Primary Liability Insurance. The maximum required private primary liability insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims.

(Continued)

Excess Liability Insurance. This policy currently provides approximately $9.3 billion of coverage through the Price-Anderson Act's mandatory industry-wide secondary insurance program of risk pooling. The $9.3 billion of coverage is the sum of the current potential cumulative retrospective premium assessments of $88 million per licensed commercial nuclear reactor. This $9.3 billion will be increased by $88 million as each additional commercial nuclear reactor is licensed, or reduced by $88 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary insurance, licensees may be assessed up to $88 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $88 million amount is subject to indexing for inflation and may be subject to state premium taxes.

Duke Energy is a member of Nuclear Electric Insurance Limited (NEIL), which provides property and business interruption insurance coverage for Duke Energy's nuclear facilities under the following three policy:

Primary Property Insurance. This policy provides $500 million in a primary property damage coverage for each of Duke Energy's nuclear facilities.

Excess Property Insurance. This policy provides excess property, decontamination and decommissioning liability insurance in the following amounts: $2.25 billion for the Catawba Nuclear Station and $1.5 billion each for the Oconee and McGuire Nuclear Stations.

Business Interruption Insurance. This policy provides business interruption and/or extra expense coverage resulting from an accidental outage of a nuclear unit. Each unit of the McGuire and Catawba Nuclear Stations is insured for up to approximately $4 million per week and the Oconee Nuclear Station units are insured for up to approximately $3 million per week. Coverage amounts per unit decline if more than one unit is involved in an accidental outage. Initial coverage begins after a 12-week deductible period and continues at 100% for 52 weeks and 80% for the next 110 weeks.

If NEIL's losses ever exceed its reserves for any of the above three programs, Duke Energy will be liable for assessments of up to five times its annual premiums. The current potential maximum assessments are as follows: Primary Property Insurance - $31 million; Excess Property Insurance – $36 million; Business Interruption Insurance - $29 million.

The other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of any liabilities for retrospective premiums and other premium assessments resulting from the Price-Anderson Act's excess secondary insurance program of risk pooling or the NEIL policies.

(Continued)

(15) Derivative Financial Instruments

The Agency has only limited involvement with derivative financial instruments.

In May 2000, the Agency entered into two identical interest rate swap agreements, each with termination dates of January 1, 2024. The Agency's objective for entering into these interest rate swap agreements is to maximize income. Under these fixed to variable interest rate swaps, PMPA receives a fixed rate of 5.93% through December 31, 2004 and a fixed rate of 5.63% thereafter, while paying a variable rate based on the BMA Municipal Swap Index. The notional amount of each of these agreements is $51,908.

In March, 2001, the Agency entered into an additional interest rate swap with a termination date of January 1, 2021. This swap is designed to mitigate interest rate risk of outstanding variable rate debt during rising interest rate periods and augment expected income during falling interest rate periods. PMPA receives a floating LIBOR rate and pays a floating variable rate based on the BMA Municipal Swap Index. The notional amount of this agreement is $100,000.

The fair value of the three interest rate swap agreements was approximately $3,431 and $3,610 at December 31, 2001 and 2000, respectively. Current market pricing models were used to estimate fair value of interest rate swap agreements. The fluctuation in the fair value of the interest rate swaps was a decrease of $179 in 2001 and is included in net increase in fair value of investments and derivative instruments in the statement of revenue and expenses. Total income from the interest rate swaps was $3,638 and $1,076 in 2001 and 2000, respectively, and is included in other expense, net, in the statements of revenues and expenses.

In October 2000, the Agency entered into a forward delivery agreement with a term of five years. The Agency's objective for entering into this forward delivery agreement is to maximize investment income. The agreement entitles the Agency to receive interest at a fixed rate of 6.4825% on scheduled monthly deposits into certain debt service principal and interest accounts. The fair value of the forward delivery agreement was approximately $1,401 and $782 at December 31, 2001 and 2000. The fluctuation in the fair value of the forward delivery contract was an increase of $619 in 2001 and is included in net increase in fair value of investments and derivative instruments in the statement of revenue and expenses. Total income from the forward delivery agreement was $214 and $1,158 in 2001 and 2000, respectively, and is included in interest income in the statements of revenues and expenses.

By using derivative instruments the Agency exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of the derivative contract is positive, the counterparty owes the Agency, which creates repayment risk for the Agency. When the fair value of a derivative contract is negative, the Agency owes the counterparty and, therefore, does not possess repayment risk. The Agency minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

Market risk is the adverse effect on the value of financial instruments that results from a change in interest rates. The market risk associated with interest-rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

Supplementary Information

PIEDMONT MUNICIPAL POWER AGENCY

Schedule of Revenue and Expenses
Per the Bond Resolution and Other Agreements

Year ended December 31, 2001
(Dollars in thousands)

		Actual Revenues and Expenses	Budgeted Revenues and Expenses	Actual Over (Under) Budget
Revenue:				
Sales of electricity to participants	$	117,548	117,904	(356)
Sales of electricity to Duke		9,303	8,432	871
Sales of electricity to others		6,905	4,364	2,541
Interest income		26,772	26,538	234
Other		1,207	1,207	—
Total revenue	$	161,735	158,445	3,290
Expenses.				
Catawba operating expenses:				
Operation and maintenance	$	22,337	21,426	911
Nuclear fuel		6,958	6,458	500
Purchased power - Duke		8,744	8,261	483
Payments in lieu of taxes		4,385	4,618	(233)
Interconnection services.				
Purchased power:				
Duke		8,213	9,548	(1,335)
Participants		7,549	7,789	(240)
Other		263	156	107
Transmission services		4,709	4,224	485
Distribution services		1,409	1,531	(122)
Administrative and general:				
Agency		3,943	4,075	(132)
Duke		8,483	9,219	(736)
Other		2,485	3,207	(722)
Special funds deposits (withdrawals)				
Bond fund:				
Deposits from revenues		84,043	87,794	(3,751)
Liquidity facility fees		699	660	39
Reserve and Contingency fund:				
Deposits from revenue		8,412	8,784	(372)
Capital additions		(1,326)	(1,781)	455
Transfer excess funds		(7,086)	(7,003)	(83)
Decommissioning fund:				
Deposits from revenue		1,324	1,324	—
Interest income (1)		2,586	2,351	235
Revenue fund				
Working capital		7,337	(751)	8,088
Fuel		(4,726)	(5,531)	805
Rate stabilization				
Interest income (1)		10,781	10,693	88
Deposits (draws)		(26,118)	(26,117)	(1)
Supplemental power reserve.				
Interest income (1)		1,008	975	33
Transfer excess funds		(1,008)	(975)	(33)
Other capital transactions				
Bond: other		142	—	142
Plant additions:				
Reserve and contingency fund		1,326	1,781	(455)
General plant		94	178	(84)
Distribution plant		43	20	23
Fuel acquisitions		4,726	5,531	(805)
Total expenses	$	161,735	158,445	3,290

(1) Included in "Revenue Interest Income"

Schedule 2

PIEDMONT MUNICIPAL POWER AGENCY

Schedule of Revenue and Expenses
Per the Bond Resolution and Other Agreements

Year ended December 31, 2001
(Dollars in thousands)

		Funds							
		Revenue		Operating	Bond		Reserve and Contingency	Decommission	Supplemental Power
		Working Capital	Rate Stabilization	Fuel Account	Principal Interest Retire	Reserve			
Balances at beginning of year:									
Assets		$ 65,402	171,118	28,271	46,544	83,850	8,385	35,419	15,000
Liabilities		(10,299)							
Net		55,103							
Project revenues:									
Participants – Electric	(1)	117,548							
– Facilities rent	(1)	1,146							
– Control services	(1)	13							
– Other	(1)	48							
Duke Power – Electric	(1)	9,303							
Other – Surplus Electric	(1)	6,905							
Interest income	(1)	12,397	10,781					2,586	1,008
Project costs (see note)									
Operations and maintenance	(2)	(22,337)							
Fuel	(3)	(6,958)		6,958					
Purchased power - Duke	(2)	(8,744)						1,324	
Decommissioning	(3)	(1,324)							
General and administration	(2)	(11,216)							
Payments in lieu of taxes	(2)	(4,356)							
Other	(2)	(2,485)							
Debt service	(3)	(84,043)			84,043				
Liquidity facility fee	(3)	(699)			699				
Reserve and contingency	(3)	(8,412)					8,412		

PIEDMONT MUNICIPAL POWER AGENCY

Schedule of Revenue and Expenses
Per the Bond Resolution and Other Agreements

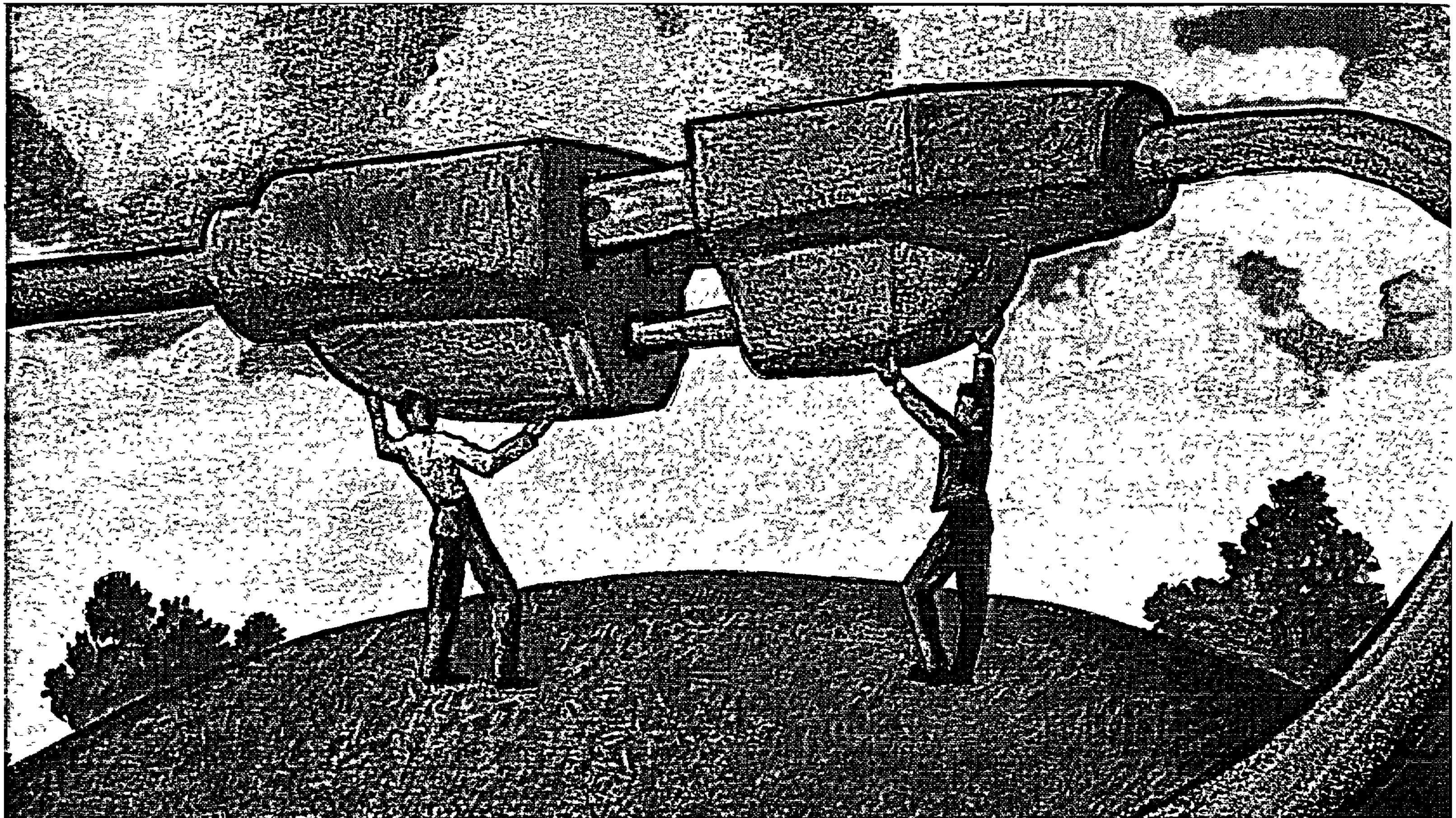
Year ended December 31, 2000

(Dollars in thousands)

		Funds							
		Revenue		Operating	Bond		Reserve and Contingency	Decommission	Supplemental Power
		Working Capital	Rate Stabilization	Fuel Account	Principal Interest Retirement	Reserve			
Supplemental power costs.									
Purchased Power – Duke	(2)	(8,213)							
– Participants	(2)	(7,549)							
– Other	(2)	(263)							
Transmission services	(2)	(4,709)							
Distribution services	(2)	(1,409)							
General and administration	(2)	(1,210)							
Payment in lieu of taxes	(2)	(30)							
Other fund changes									
Transfers in (out):									
Rate stabilization	(3)	26,118	(26,118)						
Excess funds	(3)	8,094					(7,086)		(1,008)
Reimbursement	(3)	1,326					(1,326)		
Payments.									
Debt retire/interest	(2)	(142)			(82,365)				
Capital additions	(2)	(1,462)		(4,726)					
Balances at December 31, 2001		$ 62,440	155,781	30,503	48,921	83,850	8,385	39,329	15,000
Assets		$ 74,895							
Liabilities		$ (12,455)							

(1) Deposited in appropriate fund
(2) Paid to third parties
(3) Transfers between funds

Note 1: In accordance with the Bond Resolution, third party payment requirements (except debt service payments) are transferred from Revenue Fund (Working Capital) to the Operating Fund and actual disbursements are made from the Operating Fund



UNITED IN POWER

2001 ANNUAL REPORT

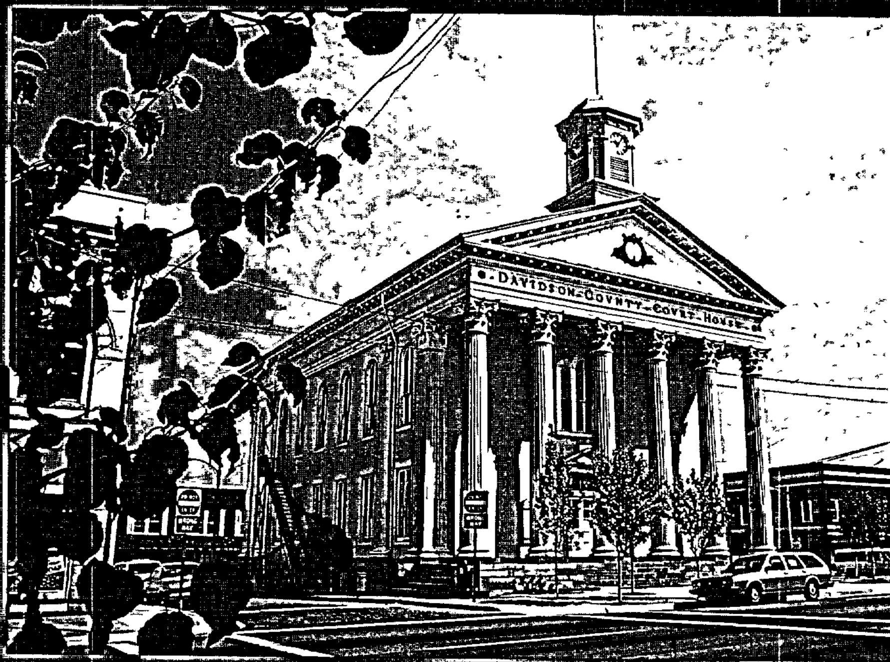
North Carolina Municipal Power Agency Number 1
North Carolina Eastern Municipal Power Agency

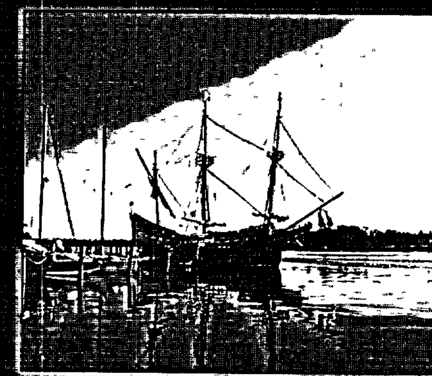
ELECTRICITIES

ElectriCities of North Carolina, Inc.

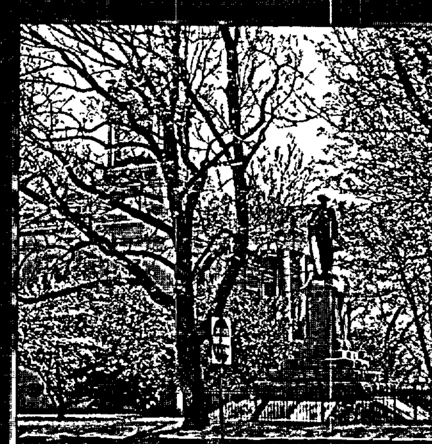
Table of Contents

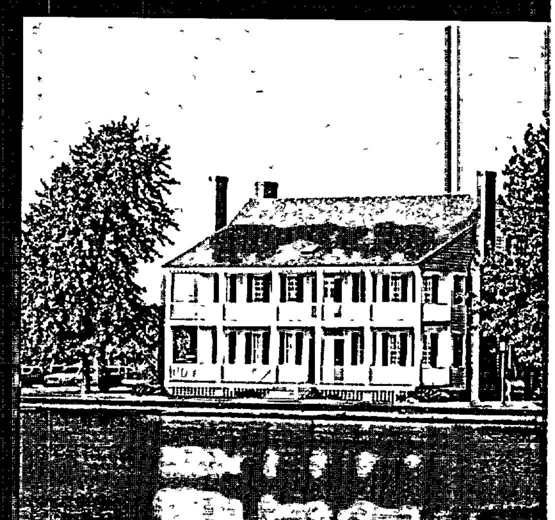
The audit reports of and financial information regarding each North Carolina Municipal Power Agency are included in this report. Each Power Agency is a separate and distinct legal entity and the inclusion of such information regarding both entities should not be construed to indicate any relationship between the two





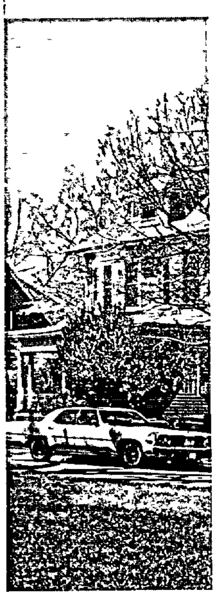
Public power towns stretch across the entire state of North Carolina offering various climates, beauty and attractions for anyone to enjoy. There are 19 cities in western North Carolina that make up North Carolina Municipal Power Agency Number 1 (NCMPA1) and 32 cities in eastern North Carolina that make up North Carolina Eastern Municipal Power Agency (NCEMPA). There are also more than 20 independent cities that are wholesale distributors of electricity.





Unity is Power

It brightens a dark night, keeps us warm in the winter and cools us in the summer. It entertains us and helps to keep us safe It plays such an integral part in our daily lives, yet most of us rarely think about it. It's electricity We don't give a lot of thought to the power that makes our lives so easy. We don't worry about how we get our electricity, just as long as it's there when we need it. That's where public power communities really shine



In the late 19th century, a wonderful invention called electricity was finally becoming a useful part of our daily lives But many power companies weren't willing to extend lines to smaller, more rural communities. They were too far away or there were not enough residents to justify the costs. So towns began building their own electric generating plants and putting up their own wires and poles. As more cities realized the early benefits of citizen ownership of electric systems, more communities wanted it for themselves Municipally owned electricity gave citizens control of their power supply. Neighbors and friends made local electric decisions and customer service was a top priority.

During the 1970's, North Carolina's public power towns began joining forces to ensure their residents, businesses and the state had a reliable and plentiful supply of power With an energy crisis worsening, threats of blackouts, and power companies teetering on bankruptcy, state voters overwhelmingly approved the concept of municipal power agencies North Carolina Eastern Municipal Power Agency and North Carolina Municipal Power Agency Number 1 were born Today 51 cities across North Carolina are partnered with Duke and CP&L. They have joint ownership in nuclear plants and coal fired plants. It's an arrangement that helped to build new generation for North Carolina It kept the lights on and helped North Carolina grow and prosper

In the 1990's, Congress set the stage for the 21 cities that buy their power wholesale. The non-power agency cities have used this new law to search the market for better prices, which helps with economic development and lower electric rates

Today all these public power communities continue to shine in North Carolina and the reasons are simple. Public power is locally controlled and locally operated. Friends and neighbors are the utility employees The electric revenue stays in town and helps these public power communities grow and prosper. North Carolina's Public Power communities are united in power to ensure they provide their citizens with a safe, secure, and reliable supply of electricity

Unity is Strength

A Letter from the Chairman and CEO

Jesse C. Tilton, III,
Chief Executive Officer
John T. Walser, Jr.,
Chairman, Board of Directors

We've all heard the old saying, "there is strength in numbers " That's the whole idea behind ElectriCities A unified group of cities, providing power to their residents with service that is second to none As we prepare for the coming years, our commitment to our customers must remain our top priority But to achieve that goal and remain a quality provider of electricity we must be united

After six years of intense deregulation debate, customer choice was put on the back burner in 2001. The State Legislature was focused on a budget shortfall and an economy on the downturn. Meantime our cities were proving what we have said all along. We are responsible, reliable distributors of electricity and good stewards to our bondholders. We are paying off our debt on schedule. We have reduced the rate of transfers and continue looking for ways to keep our costs down The Power Agency cities as a group are in compliance with the Local Government Commission (LGC) transfer policy Our residents have a safe and plentiful supply of power. Our utilities are proving that neighbors serving neighbors is a good way to do business. Our cities consistently restore power faster than other utilities and receive high marks when it comes to the questions and concerns of their customers.

Now we must stay the course. With a shift away from deregulation, we must strengthen our bond with one another. We each have individual strengths and challenges unique to our communities, but when we combine our resources and the vast expertise of those who work for our cities, everyone benefits. A unified voice also means political clout as we put forth the positive message that public power is good for North Carolina!

The cities that provide power to their people want to continue that service because they do it well But the reasons go much deeper. Our city leaders want to ensure a higher quality of life for their residents not only today, but also well into the future.

So to our cities we say, join hands in a spirit of unity and togetherness. There is nothing like a strong and powerful group to show others that our commitment is real and our partnership is strong.

ElectriCities Leadership

2001 Board of Directors

John T. Walser, Jr.
Chairman, Lexington

R.L. Willoughby
Vice Chairman, Washington

Winton R. Poole
Secretary, Cornelius

William H. Batchelor
Rocky Mount

Steven K. Blanchard
Fayetteville

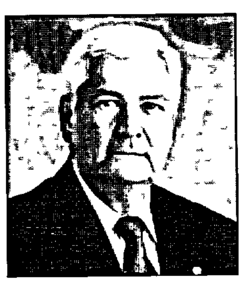
Malcolm A. Green
Greenville

Steven L. Harrell
Elizabeth City

Barry C. Hayes
Granite Falls

Franz F. Holscher
Gastonia

J. William McGuinn, Jr.
High Point



Jack F. Neel
Albemarle

Samuel W. Noble
Tarboro

Stephen H. Slough
Concord

Edward A. Wyatt
Wilson

ElectriCities Management

- Jesse C Tilton, III, Chief Executive Officer
- Arthur L. Hubert, Jr., Chief Operating Officer
- Al M Conyers, Chief Financial Officer
- Mark H Otersen, Director, Marketing & Regional Services
- Alice D Garland, Director, Public Affairs
- Kenneth M Raber, Director, NCEMPA Operations
- Steve R Shelton, Director, NCMPA1 Operations
- Clay A Norris, Director, Planning

ElectriCities Membership

Alphabetical Listing of Member Cities & Towns in 2001

City/Town	Year Electric System Established	Customers
• Abbeville, SC	1905	3,626
• Albemarle	1910	11,333
• Apex	1917	9,154
• Ayden	1916	3,695
• Bamberg, SC	1905	1,784
• Bedford, VA	1911	6,729
• Belhaven	1920	1,139
• Bennettsville, SC	1903	4,950
• Benson	1913	1,800
• Black Creek	1922	685
• Blackstone, VA	1888	2,079
• Bostic	1920	193
• Camden, SC	1902	10,000
• Cherryville	1920	2,890
• Clayton	1913	4,082
• Clinton, SC	1907	4,377
• Concord	1901	23,997
• Cornelius	1916	1,866
• Culpeper, VA	1934	3,054
• Dallas	1925	2,851
• Danville, VA	1886	48,718
• Drexel	1926	1,236
• Easley, SC	1911	12,000
• Edenton	1908	3,899
• Elizabeth City	1926	10,717
• Elizabeth City State University	1891	University
• Elkton, VA	1924	1,020
• Enfield	Prior to 1940	1,538
• Farmville	1904	2,888
• Fayetteville	Chartered 1905	67,128
• Forest City	Early 1900s	4,732
• Fountain	1903	372
• Franklin, VA	1892	5,242
• Fremont	1918	869
• Gaffney, SC	1907	7,300
• Gastonia	1919	25,591
• Granite Falls	1923	2,318
• Greenville	1905	51,662
• Greer, SC	1914	10,991
• Hamilton	1922	254
• Harrisonburg, VA	1957	16,217
• Hertford	1915	1,271
• High Point	1893	36,033
• Highlands	1926	2,519
• Hobgood	1922	320
• Hookerton	1907	422
• Huntersville	1916	3,125
• Kings Mountain	1935	3,943
• Kinston	1897	16,528
• La Grange	1917	1,524

ElectriCities Membership

Alphabetical Listing of Member Cities & Towns in 2001

City/Town	Year Electric System Established	Customers
Landis	1919	2,607
Laurens, SC	1922	5,305
Laurinburg	1925	5,932
Lexington	1904	18,212
Lincolnton	1900	2,841
Louisburg	1906	1,940
Lucama	1889	1,145
Lumberton	1915	10,066
Macclesfield	1928	302
Maiden	1920	1,030
Manassas, VA	1912	14,341
Martinsville, VA	1900	8,176
Monroe	1900	9,304
Morganton	1899	8,045
Murphy	1953	4,173
New Bern	1901	16,821
New River Light & Power (Boone)	1915	7,054
Newberry, SC	1923	4,789
Newton	1896	4,401
Pikeville	1918	527
Pinetops	1925	730
Pineville	1939	2,373
Red Springs	1910	1,916
Richlands, VA	1922	2,500
Robersonville	1919	1,220
Rock Hill, SC	1911	26,642
Rocky Mount	1902	29,097
Scotland Neck	1903	1,630
Selma	1913	2,705
Sharpsburg	1920	1,596
Shelby	1912	8,136
Smithfield	1912	4,568
Southport	1916	2,086
Stantonsburg	1920	1,203
Statesville	1889	12,501
Tarboro	1897	5,797
UNC-Chapel Hill	1895	University and 430 campus retail customers
UNC-Greensboro	1919	University
Union, SC	1896	7,025
Wakefield, VA	1920	564
Wake Forest	1909	4,900
Walstonburg	1922	135
Washington	1903	12,384
Waynesville	1923	2,966
Western Carolina University	1920	2,086
Westminster, SC	1921	1,808
Wilson	1892	30,990
Windsor	1920	1,758
Winterville	1900	1,985

North Carolina Municipal
Power Agency Number 1

The Customer is First

Chairman Letter to Stakeholders

Richard L. Thomas
Mayor, Lexington
Chairman, NCMPA1

North Carolina appeared to be on the fast track to electric deregulation during the year 2000 The likelihood that electric industry restructuring was imminent compelled us to devote much of our time and energy preparing for it

Now, one year later, nearly everything has changed.

Due to events in California, deregulation was put on hold early in 2001 Although we continue to keep an eye on how restructuring is progressing in other states, we are now able to refocus our attention on our customers and on providing the best possible service for them.

As members of the public power community, we maintain an enviable position. Individually, we have the autonomy to determine how best to serve the customers in our cities and towns At the same time, our membership in this "fraternity" enables us to partner with other public power municipalities on projects that achieve savings and other benefits for consumers

The past year is notable largely because of the many cost saving regional opportunities we recognized. The collaborative efforts that ensued resulted in several significant accomplishments that will benefit the members of NCMPA1 for years to come.

Together with Cayenta and ElectriCities, we began offering our members a new Customer Information System (CIS) The CIS will help cities streamline their billing procedures and increase efficiency through a program designed specifically for municipalities It will also allow the cities that comprise NCMPA1 to share common software, staff expertise, and support.

We are in the process of installing 10 diesel generators in cities throughout western North Carolina as part of our distributed generation project. These generators will better enable us to meet peak demand during the summer months when demand is high, as well as support our sales of energy to the wholesale market. As a result of this endeavor, we anticipate a savings in supplemental power purchases of $10 million over the next 10 years

Last summer Duke filed a petition with the Nuclear Regulatory Commission to renew the operating licenses for both McGuire and Catawba nuclear stations Approval of its license extension would allow the Catawba Plant to continue operations into the 2040's, assuring our member cities and their customers a safe, reliable, and economical power supply for many years to come.

Effective January 1, 2001, NCMPA1 entered into the wholesale market for its supplemental power Contracts with Georgia Power Company through 2005 and one year deals with Dynegy and Entergy-Koch Trading provided for power supply when requirements were in excess of the Catawba project during 2001. Later, in the fall, NCMPA1 contracted for our 2002 summer power supply needs with EKT and Aquila.

Finally, we issued an RFP in 2001 that offers more structured sales of our Catawba resource It also examines replacing that power with peaking power from the wholesale market At the end of the year, we were in negotiations for new power supply arrangements.

These are but a few of our many successes in 2001. I believe our willingness to unite on these important issues made each of them not just a possibility — but a reality That's why "United in Power" is not just a slogan, but rather is an apt description of the good we can accomplish when we join together.

NCMPA1 Leadership

2001 Board of Commissioners • 2001 Officers

Richard L. Thomas
Chairman
Mayor, Lexington

Morris A. Baker
Vice-Chairman
Town Manager, Drexel

Arnold J. Koonce, Jr.
Secretary-Treasurer
Mayor, High Point

Commissioners and Alternate Commissioners

Alternate commissioner's names appear in italics

• Albemarle
Mr Raymond I Allen
First Alternate vacant
Mr Jack F. Neel

• Bostic
Commissioner Vacant
Mr James Morrow

• Cherryville
Mr Jerry J Hudson
Mayor Wade H Stroupe, Jr

• Cornelius
Mr James R. Bensman
First Alternate Vacant
Mr Thurman Ross, Jr

• Drexel
Mr Morris A. Baker
Mr Benny J Orders

• Gastonia
Mr Franz F. Holscher
Mr Bob Wilkerson

• Granite Falls
Ms Linda K. Story
Dr Caryl B. Burns
Mayor Barry C. Hayes

• High Point
Mayor Arnold J. Koonce, Jr.
Mr. Stribling P Boynton

• Huntersville
Mr Alex Barnette
Mr Jerry E Cox

• Landis
Mr Tommy Branch
First Alternate Vacant

• Lexington
Mayor Richard L Thomas
Mr C Phillip Head, Sr
Mr L. Klynt Ripple

• Lincolnton
Mr. Stephen H Peeler
Mr Jeff B. Emory
Mayor Bobby G Huitt

• Maiden
Mr Kevin C Sanders
Mr Kent M Auton

• Monroe
Mr Donald D Mitchell
Mr Robert J Smith
Mr S. Douglas Spell

• Morganton
Mr Dan Brown
Ms. Sally W. Sandy
Mr Steve B Settlemyer

• Newton
Mr Edward F Burchins
First Alternate Vacant

• Pineville
Mayor George Fowler
Ms Mary Ann Creech

• Shelby
Mr Pete Gilbert
Mr Jay C Stowe
Ms Betsy Fonvielle

• Statesville
Mr Arthur E Peterson
Mr Herbert "Jim" Lawton
Mr Larry M Cranford

Electric System Participants

City/Town	Established	Revenues	Customers	% Ownership
• Albemarle	1910	2001 —$23,363,586 2000 —$23,824,196	11,333	7.604%
• Bostic	1920	2001 — $248,991 2000 — $243,359	193	0.087%
• Cherryville	1920	2001 — $4,458,395 2000 — $4,610,124	2,890	1.579%
• Cornelius	1916	2001 — $2,898,686 2000 — $2,812,310	1,866	0.362%
• Drexel	1926	2001 — $1,697,006 2000 — $1,660,610	1,236	0 507%
• Gastonia	1919	2001 —$55,587,515 2000 —$56,861,182	25,591	17 121%
• Granite Falls	1923	2001 — $4,102,781 2000 — $4,226,271	2,318	0 912%
• High Point	1893	2001 —$80,765,534 2000 —$78,419,127	36,033	18 960%
• Huntersville	1916	2001 — $4,659,163 2000 — $3,974,221	3,125	0 623%
• Landis	1919	2001 — $3,840,410 2000 — $3,485,020	2,607	1 130%
• Lexington	1904	2001 —$41,458,163 2000 —$41,001,556	18,212	12 934%
• Lincolnton	1900	2001 — $5,463,620 2000 — $5,450,148	2,841	1 608%
• Maiden	1920	2001 — $5,260,709 2000 — $5,396,878	1,030	1.289%
• Monroe	1900	2001 —$33,666,778 2000 —$33,739,383	9,304	10 038%
• Morganton	1899	2001 —$21,752,955 2000 —$22,022,361	8,045	6.735%
• Newton	1896	2001 — $7,830,840 2000 — $7,513,216	4,401	2 115%
• Pineville	1939	2001 — $8,788,260 2000 — $8,231,250	2,373	0 536%
• Shelby	1912	2001 —$14,466,423 2000 —$14,753,612	8,136	5 996%
• Statesville	1889	2001 —$31,136,866 2000 —$30,736,338	12,501	9 864%

Operational Highlights

Plant Information

	Capacity* Factor %	Availability* Factor %
• Catawba Unit 1	100 9	99.6
• Catawba Unit 2	86.7	85.7
• McGuire Unit 1	90.1	88 0
• McGuire Unit 2	102.7	100 0

** These numbers are reported by Duke to the Nuclear Regulatory Commission in the units' December 2001 Operating Data Report*

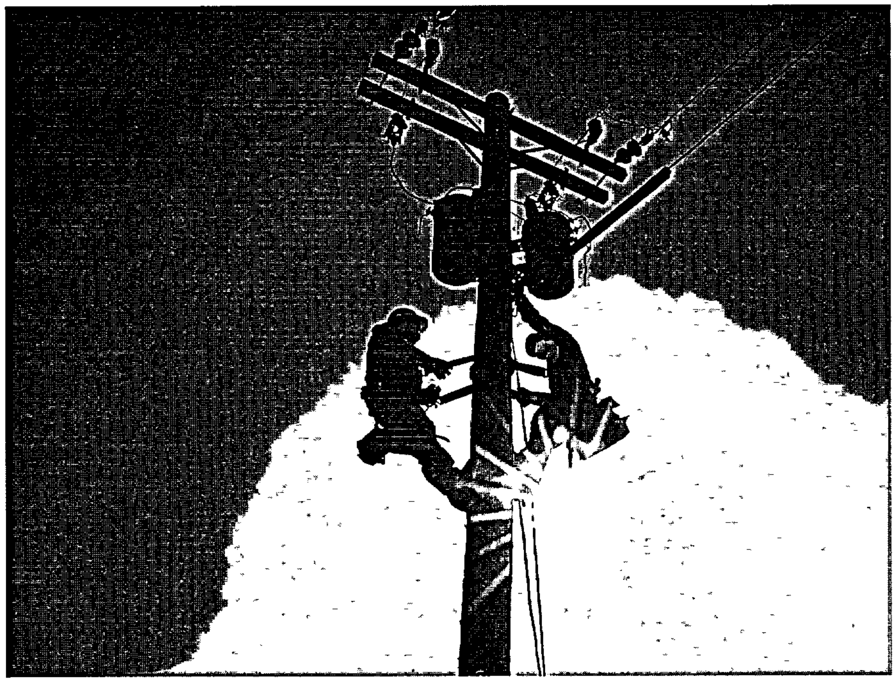
Catawba Unit 1 did not have a refueling outage in 2001. The next refueling outage is scheduled for April 27, 2002.

Catawba Unit 2 began a refueling outage on September 15, 2001 that ended on October 23 The next refueling outage for Unit 2 is scheduled to begin in March 2003.

McGuire Unit 1 began a refueling outage on March 9, 2001 that ended on April 17 The next refueling outage for the unit is scheduled to begin September 13, 2002

McGuire Unit 2 did not have a refueling outage in 2001. Unit 2 began a refueling outage February 22, 2002 that is scheduled to end on March 25.

Catawba Unit 1 and McGuire Unit 2 placed in the top 50 nuclear units in the world based upon gross generation in 2001. Catawba Unit 1 and McGuire Unit 2 were 15th and 24th, respectively



Making upgrades and keeping up with repairs means safe and reliable power It also ensures the electric distribution system will remain a valuable part of the community

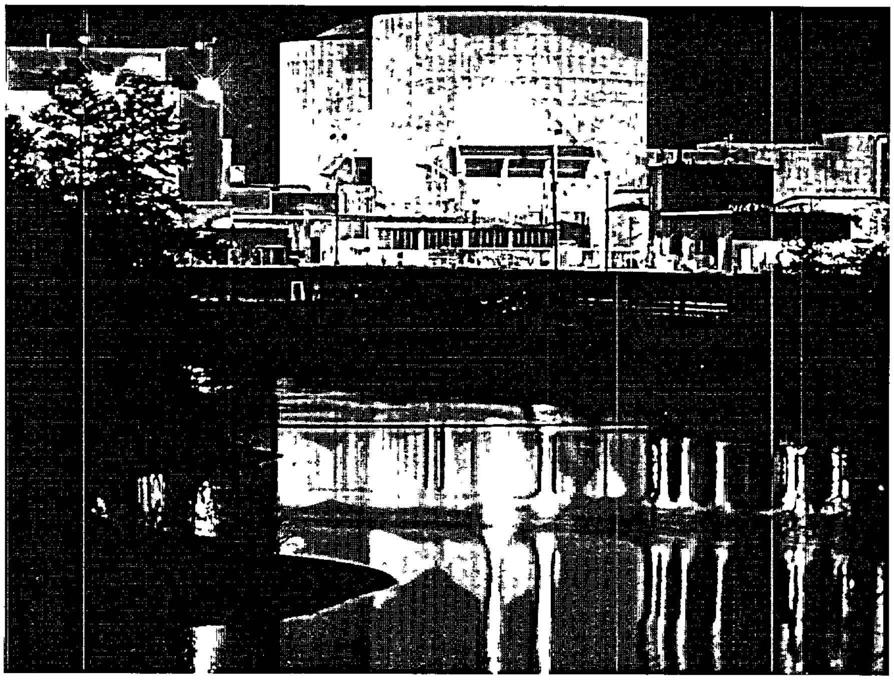
New Supplemental Power and Transmission Arrangements

On January 1, 2001, NCMPA1 no longer purchased power from Duke Energy for its requirements above its Catawba Project entitlement. To meet its supplemental power requirements, NCMPA1 has entered a five-year contract with Georgia Power Company for the purchase of 125 MW which began on January 1, 2001. NCMPA1 also has the right to schedule and receive 42 MW of power from the Southeastern Power Administration. In addition, NCMPA1 purchased 50 MW of firm capacity from Dynegy Power Marketing, Inc., from their Rockingham County North Carolina Units 1 through 4 and 50 MW of System Firm Energy delivered to the Duke control area from Entergy-Koch Trading, from their Dayton Power and Light Company Resources for June 1, 2001 through August 31, 2001.

NCMPA1 also purchases transmission services for its native load requirements from Duke Electric Transmission in accordance with Duke's Open Access Transmission Tariff To effectuate this new service, all the required agreements and amendments to existing agreements have been filed and approved by the Federal Energy Regulatory Commission.

On January 1, 2001, NCMPA1 also became responsible for scheduling and delivering power for all of its requirements above its Catawba Project entitlements NCMPA1 has entered a two-year contract with Entergy-Koch Trading to serve as NCMPA1's resource manager Entergy-Koch Trading has the responsibility of managing and marketing all of NCMPA1's

Operational Highlights



NCMPA1 has 75% ownership of Catawba Nuclear Station Unit 2 located on Lake Wylie in South Carolina. The unit began commercial operation in 1986. NCMPA1 has two employees that work on-site at Catawba.

surplus energy. For 2001, NCMPA1 had revenues of $36.3 million from surplus energy sales.

In addition, Entergy-Koch Trading is responsible for scheduling the delivery of energy to meet NCMPA1's energy requirements above its Catawba Project entitlement. NCMPA1's Peak Demand in 2001 was 989 MW.

Catawba and McGuire Operating License Extension

Duke Energy submitted concurrent applications for Operating License Extensions for all four units at the Catawba and McGuire Nuclear Stations on June 13, 2001. Submitting the applications for the four very similar units together is projected to provide significant cost savings as compared to separate applications for each Station. Duke believes that the Catawba and McGuire applications are on track and proceeding basically as expected. Duke previously submitted applications for Operating License Extensions for its three Oconee Units on July 6, 1998. The NRC approved the 20 year License Extensions for the Oconee Units on May 23, 2000.

Distributed Generation

The decision was made in 2001 to construct 18.25 MW of diesel fueled distributed generation. The project consists of ten 1,825 kW generators located at city delivery points. The generators are scheduled to be available for service by June 1, 2002. Also, NCMPA1 has been successful in placing under contract approximately 45 MW of generation owned by cities and retail customers. This generation is available for NCMPA1 power supply during times of high demand and spiking wholesale prices.

Load Management

More than $8,000,000 worth of savings were passed on to customers as a result of NCMPA1's load management operations. These efforts successfully reduced an average of 85 MW of peak demand each month.

Economic Development

The western cities continue success with industry recruitment and expansion of their existing businesses. In 2001, NCMPA1 members added 1,023 new jobs to their communities with investments totaling $207,655,165. New load added to the Agency totaled more than 15 MW. NCMPA1 staff continues efforts with the Department of Commerce and the Regional Partnerships to further the strategic load growth efforts in our communities.

Advertising and direct mail was focused on automotive, pharmaceutical and medical instruments, boat manufacturers/suppliers, high technology, electronics, telecommunications, biotechnology, rubber and plastics, research and development, and software development industries. There

Operational Highlights

were approximately 90 inquiries made which resulted in numerous site visits.

Marketing

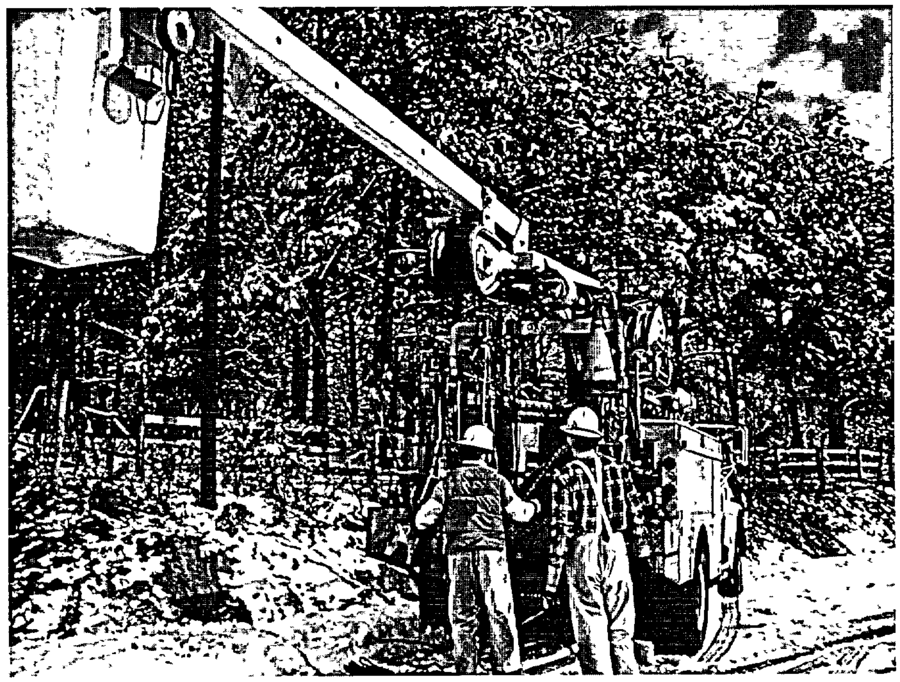
During 2001, NCMPA1 and its participants continued efforts to strengthen business relationships with their largest industrial and commercial customers. The customer retention program is designed to help industries and businesses in member communities to become more efficient consumers of electricity.

The largest industrial and commercial customers provide vital jobs and a broader tax base to the communities where they are located. Helping these customers improve their operational efficiencies helps to ensure these companies will prosper in the member cities

The customer retention program includes innovative rates, educational opportunities on such subjects as electric motors and drives, predictive maintenance, compressed air, and our Energy Solutions Partner (ESP) program. ESP offers alliance partnerships that have been formed to provide solutions to our members' customers' needs Our lead backup generation partner sold over 1,000 kW of new generation to NCMPA1 customers in 2001. Other ESP solutions include lighting, demand controllers, and power quality.

Huntersville & Cornelius

The merger of Huntersville and Cornelius electric operations in 1997 continues to show reduced operating costs, exceptional customer service, and value for customers of the towns. In July 2001, the combined electric department celebrated its four year anniversary and achievements with an employee appreciation luncheon. Among other achievements in 2001, the department received the highest safety award given by the NC Association of Municipal Electric Systems for working in excess of 35,000 hours without an accident or injury.



Public power crews are at work no matter what the weather. In most cases electricity is restored faster in public power communities because the crews live in the towns where they work.

Reduced operating costs and economies of scale from double-digit load growth have enabled both towns to reduce electric rates. As both towns and the region continue to grow and best practices are implemented, operating costs continue to decline.

Providing safe, responsive, and value-added customer service is emphasized in daily operations. Customers have already seen improvements in bill information, format, and payment options. Further improvements are expected as both towns transition to a new computer and billing system in the future.

The Huntersville/Cornelius merger has been successful and shows that regionalization of electric systems is possible and economical for customers and towns

Customer Retention Program

2001 saw ongoing efforts by NCMPA1 and its participants to strengthen business relationships with their largest industrial and commercial customers NCMPA1 continues

Operational Highlights

to expand the level of energy information available to these customers through its Customer Billing System.

Retail Billing Services

NCMPA1 expanded its retail billing services to the cities this year by 20 percent for a total of 300 accounts in the Customer Billing System. NCMPA1 uses this system to provide retail billing assistance and load profile data for the cities' largest customers in the Customer Retention Program. In 2001, NCMPA1 further extended the service to new industrial and commercial customers on innovative retail rates that could not be easily accommodated by the billing systems in the cities NCMPA1 is currently providing city staff members with internet access to the customer metering and billing data Through a secure extranet site, authorized city staff members can view their city's customers' usage history and other related information The Agency will begin marketing access to the site by the customers themselves in 2002. Information gathered from real time meters that is maintained in the data warehouse will provide customers with useful information concerning their usage patterns and billing history, thus enabling them to make more efficient use of their energy resources.

NCMPA1 also provides retail-billing services for the Town of Pineville through its Huntersville/Cornelius office Huntersville/Cornelius office staff work with the town each month in processing billing information for approximately 2,600 customers

Customers in public power towns can take care of business locally (usually town hall) They can also pick up the phone and deal with a real live person, instead of an automated system

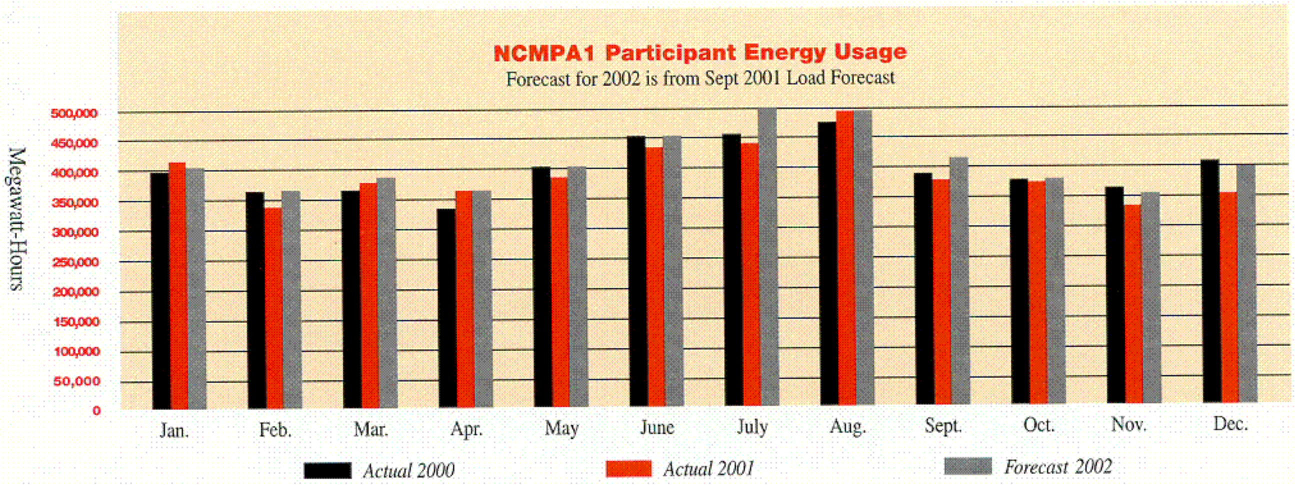
Wholesale Rates

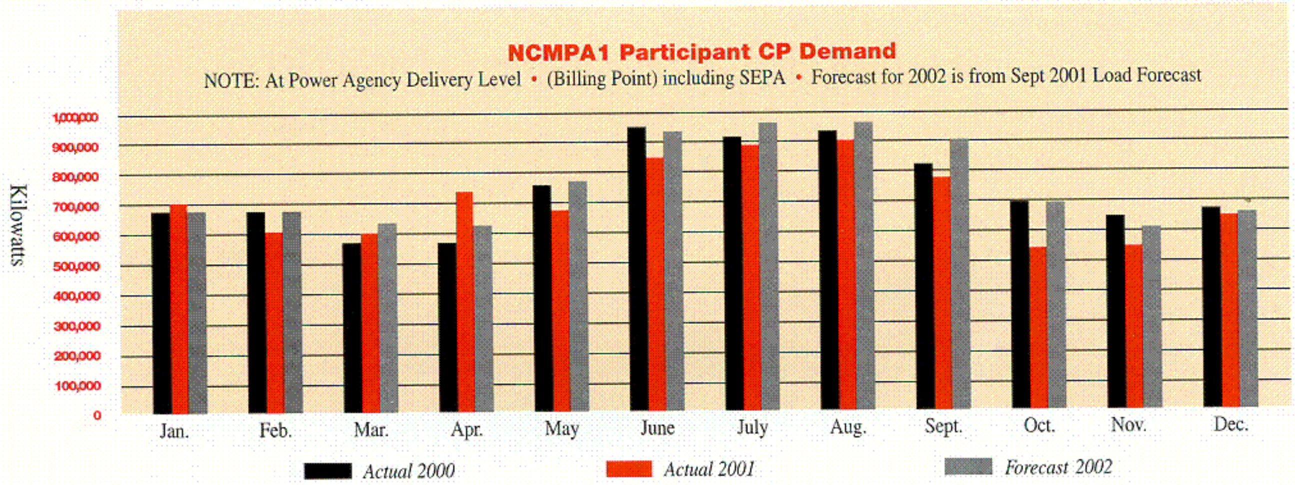
The Agency had a 2% wholesale rate increase this year. NCMPA1 developed wholesale rate alternatives to meet its future power supply needs.

Security

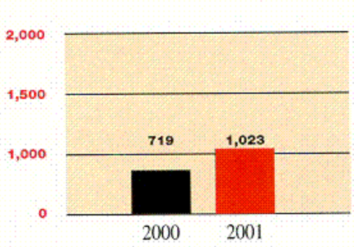
Following the terrorist attacks on the World Trade Center and the Pentagon on September 11, 2001, the nation's nuclear power plants have come under scrutiny about whether they could withstand a terrorist strike As a result of the 9/11 events, nuclear power plants across the United States have upgraded their already impressive security measures Nuclear Regulatory Commission regulations require that these plants have a professional security staff and demonstrate they can withstand an attack from a group armed with automatic weapons, explosives and insider assistance Under the contractual arrangement with NCMPA1, Duke Energy handles all issues of security in accordance with federal regulations Duke is closely coordinating with federal, state, and local authorities and they have taken and will continue to take appropriate steps to ensure safety and security at the Catawba Nuclear Station Unit 2 in which NCMPA1 has 75 percent ownership

Operational **Highlights**

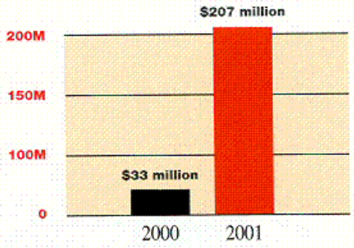




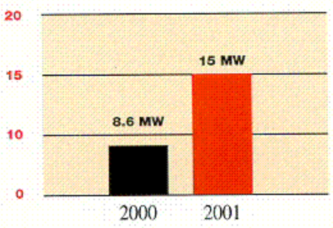
NCMPA1 Economic Development



Number of New Jobs



Investments in Millions



Megawatt Growth

C01

Financial Information

Investment Portfolio Statistics

Earnings

*Earnings**	*Income*	*Rate of Return*
• 2001	$51,850,000	6.06%
• 2000	$55,857,000	6.37%

Market Value as of 12/31*

	Value	*Average Maturity*
• 2001	$948,926,000	4 5 years
• 2000	$959,519,000	5 1 years

Transactions

	Number	*Amount*
• 2001	670	$9,685,535,000
• 2000	643	$7,450,227,000

* *For Earnings and Market Value, amounts include income from and market value of securities held in the decommissioning trust*

Debt Outstanding

Debt Outstanding 12/31

	Balance	*Weighted Average Interest Cost*
Fixed Rate Bonds		
• 2001	$2,212,436,000	5.97%
• 2000	$2,271,884,000	6 01%

NCMPA1 Bond Reconciliation

• Bonds Outstanding 12/31/00	$2,271,884,000
• Matured 1/1/01	- 59,448,000
• Bonds Outstanding 12/31/01	$2,212,436,000

NCMPA1 Bonds Outstanding

• Series 1985B	$80,575,000
• Series 1988	$5,526,000
• Series 1990	$18,410,000
• Series 1992	$1,033,855,000
• Series 1993	$484,550,000
• Series 1995A	$79,440,000
• Series 1997A	$97,775,000
• Series 1998A	$128,365,000
• Series 1999A	$83,340,000
• Series 1999B	$200,600,000

Independent Auditors' Report

We have audited the accompanying balance sheets of North Carolina Municipal Power Agency Number 1 as of December 31, 2001 and 2000, and the related statements of revenues and expenses and changes in retained earnings, and cash flows for the years then ended. These financial statements are the responsibility of the Agency's management Our responsibility is to express an opinion on these financial statements based on our audits

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North Carolina Municipal Power Agency Number 1 as of December 31, 2001 and 2000, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America

As discussed in note B to the financial statements, the Agency changed its method of accounting for derivative financial instruments in 2001

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplementary information included in the Schedules of Revenues and Expenses per Bond Resolution and Other Agreements and Schedules of Changes in Assets of Funds Invested is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

KPMG LLP

Raleigh, North Carolina • March 29, 2002

Balance Sheets

($000s)

Assets	December 31, 2001	2000
• Electric Utility Plant		
Electric plant in service, net of accumulated depreciation of $601,818 and $562,787	$ 844,504	$ 887,345
Construction work in progress	12,952	4,551
Nuclear fuel, net of accumulated amortization of $101,233 and $81,266	41,830	46,648
	899,286	938,544
• Non-Utility Property and Equipment, net	2,108	2,180
• Special Funds Invested (Notes C and E).		
Bond fund	319,704	318,661
Reserve and contingency fund	20,270	17,229
Special reserve fund	1,104	1,028
	341,078	336,918
• Trust for Decommissioning Costs (Notes D and E)	128,263	119,769
• Operating Assets		
Funds invested (Notes C and E)		
Revenue fund	251,680	249,769
Operating fund	91,759	109,418
Supplemental fund	143,055	150,614
	486,494	509,801
Participant accounts receivable	19,280	19,905
Operating accounts receivable	2,677	5,996
Prepaid expenses	39,025	39,157
Derivative financial instruments (Note B)	12,149	
	559,625	574,859
• Deferred Costs		
Unamortized debt issuance costs	33,715	35,758
Costs of advance refundings of debt	254,745	277,712
Costs to be recovered from future billings to participants (Note D)	439,400	430,594
	727 860	744,064
	$2,658,220	$ 2,716,334

See accompanying notes to financial statements

Balance Sheets

($000s)

	December 31, 2001	December 31, 2000
Liabilities and Retained Earnings		
• Long-Term Debt		
Bonds, net of unamortized discount (Note E)	$2,051,926	$ 2,105,735
• Special Funds Liabilities:		
Construction payable	3,100	
Current maturities of bonds (Note E)	59,508	59,448
Accrued interest on bonds	57,858	62,273
	120,466	121,721
• Liability for Decommissioning Costs	117,553	103,600
• Operating Liabilities:		
Accounts payable	11,660	1,952
Accrued taxes	13,382	14,480
	25,042	16,432
• Deferred Revenues (Note D)	335,833	361,446
• Commitments and Contingencies (Note F)		
• Retained Earnings	7,400	7,400
	$2,658,220	$ 2,716,334

Statements of Revenues & Expenses

And Changes in Retained Earnings ($000s)

	Year Ended December 31, 2001	2000
• Operating Revenues		
Sales of electricity to participants	$261,063	$ 261,921
Sales of electricity to utilities	62,616	55,759
Other revenues (Note G)	775	7,266
	324,454	324,946
• Operating Expenses		
Operation and maintenance	76,708	83,348
Nuclear fuel	26,505	27,286
Interconnection services:		
Purchased power	49,766	45,730
Transmission and distribution	11,225	14,109
Other	113	134
	61,104	59,973
Administrative and general	29,584	30,851
Gross receipts and excise taxes	11,188	10,968
Property tax	12,518	12,920
Depreciation	50,069	51,233
	267,676	276,579
• Net Operating Income	56,778	48,367
• Interest Charges (Credits)		
Interest expense	117,123	123,028
Amortization of debt refunding costs	22,967	23,606
Amortization of debt discount and issuance costs	7,743	7,583
Gain on redemption of bonds		(43)
Net increase in fair value of investments and derivative financial instruments	(6,823)	(35,406)
Investment income	(42,463)	(48,612)
	98,547	70,156
• Net Cost to be Recovered From Future Billings to Participants (Note D)	34,419	21,789
• Revenues (Under) Over Expenses Before Cumulative Effect of a Change in Accounting Principle	(7,350)	0
• Cumulative Effect of a Change in Accounting Principle (Note B)	7,350	
• Excess of Revenues Over Expenses	0	0
• Retained Earnings, Beginning of year	7,400	7,400
• Retained Earnings, End of year	$ 7,400	$ 7,400

See accompanying notes to financial statements

Statements of Cash Flows

($000s)

	Year Ended December 31, 2001	2000
• Cash Flows from Operating Activities:		
Receipts from sales of electricity	$ 327,907	$ 315,463
Receipts from other revenues	775	7,266
Payments of operating expenses	(181,696)	(204,420)
Net cash provided by operating activities	146,986	118,309
• Cash Flows from Capital and Related Financing Activities:		
Interest paid	(121,538)	(118,286)
Additions to electric utility plant and non-utility property and equipment	(30,859)	(29,122)
Bonds retired	(59,448)	(55,283)
Net cash used for capital and related financing activities	(211,845)	(202,691)
• Cash Flows from Investing Activities.		
Sales and maturities of investment securities	9,490,720	7,412,283
Purchases of investment securities	(9,466,442)	(7,374,575)
Investment earnings receipts from non-construction funds	40,585	46,645
Net cash provided by investing activities	64,863	84,353
• Net Increase (Decrease) in Operating Cash	4	(29)
• Operating Cash, Beginning of year	1	30
• Operating Cash, End of year	$ 5	$ 1

See accompanying notes to financial statements.

Statements of Cash Flows [illegible]

($000s)

	Year Ended December 31, 2001	2000
• Reconciliation of Net Operating Income to Net Cash Provided by Operating Activities		
Net Operating Income	$ 56,778	$ 48,367
Adjustments:		
Depreciation	50,069	51,233
Amortization of nuclear fuel	26,505	27,286
Changes in assets and liabilities:		
Decrease (increase) in participant accounts receivable	625	(617)
Decrease (increase) in operating accounts receivable	3,319	(1,908)
Decrease in prepaid expenses	132	1,709
Increase (decrease) in accounts payable	10,656	(8,239)
(Decrease) increase in accrued taxes	(1,098)	478
Total Adjustments	90,208	69,942
Net Cash Provided by Operating Activities	$146,986	$118,309

See accompanying notes to financial statements

Notes to Financial Statements

Years Ended December 31, 2001 and 2000

A. GENERAL MATTERS

North Carolina Municipal Power Agency Number 1 (Agency) is a joint agency organized and existing pursuant to Chapter 159B of the General Statutes of North Carolina to enable municipalities owning electric distribution systems, through the organization of the Agency, to finance, construct, own, operate, and maintain electric generation and transmission facilities. The Agency has nineteen members (participants) with interests ranging from 0 0869% to 18.9600%, which receive power from the Agency

The Project

The Agency has entered into several agreements with Duke Energy Corporation (Duke) which govern the purchase, ownership, construction, operation, and maintenance of the project.

The Purchase, Construction, and Ownership Agreement provides, among other things, for the Agency to purchase a 75% undivided ownership interest in Unit 2 of the Catawba Nuclear Station (station) and a 37.5% undivided ownership interest in certain support facilities of the station (project) However, by virtue of various provisions in the Interconnection Agreement and the Operation and Fuel Agreement, the Agency (1) bears the costs of acquisition, construction, operation, and maintenance of 37.5% of Unit 1 and 37.5% of Unit 2, and (2) has the same proportionate right to the output of and bears the risks associated with the lack of operation of such units.

The Interconnection Agreement provides for the interconnection between Duke's electric power system and the Agency's project and for the exchange of power between Unit 1 and Unit 2 of the station and between the Catawba units and Duke's McGuire Nuclear Station. The agreement also provides for the purchase and sale of capacity and energy, and the transmission of energy to the Agency's participants

As part of the Interconnection Agreement, the Agency agreed to sell back to Duke, on a take-or-pay basis, capacity from each Catawba unit in decreasing amounts In calendar years 2001 and 2000, the Agency retained 100 percent and approximately 98 percent, respectively, of the Agency's share of the station's aggregate available capacity. On January 1, 2001, the sell-back arrangement terminated.

The Operation and Fuel Agreement provides for Duke to operate, maintain, and fuel the station, to make renewals, replacements, and capital additions as approved by the Agency; and for the ultimate decommissioning of the station at the end of its useful life.

The Agency's acquisition of its ownership interest is being financed by electric revenue bonds pursuant to Resolution No. R-16-78, as amended, (resolution) of the Board of Commissioners of the Agency. The resolution established special funds to hold proceeds from debt issuance, such proceeds to be used for costs of acquisition and construction of the project, and to establish certain reserves. The resolution also established special funds in which project revenues are deposited and from which project operating costs, debt service, and other specified payments relating to the project are made.

The Agency has entered into a Project Power Sales Agreement and a Supplemental Power Sales Agreement with each participant These agreements provide for each participant to purchase from the Agency its all-requirements bulk power supply, in excess of power allotments from the Southeastern Power Administration (SEPA), which includes its total share of project output (as defined by the Project Power Sales Agreement) The Agency is obligated to provide all electric power required by each participant at the respective delivery points. Each participant is obligated to pay its share of the operating and debt service costs of the project.

The Agency's participants receive their total electric power, exclusive of power allotments from SEPA, from the Agency Such power is provided by project output together with supplemental purchases of power. In accordance with an agreement between the Agency and Duke, beginning January 1, 2001, the Agency began making its supplemental purchases from another source

To meet its supplemental power requirements, the Agency has entered a five-year contract with Georgia Power Company for the purchase of 125 MW. In addition, the Agency purchased 100 MW from two suppliers for June through August.

Pursuant to two "Reliability Exchanges" contained in the Interconnection Agreement, project output is provided in essentially equal amounts from Catawba Unit 2 and three other nuclear units (Catawba Unit 1, McGuire Unit 1, and McGuire Unit 2) in operation on the Duke system, all of similar size and capacity. The reliability exchanges are intended to make more reliable the supply of capacity and energy to the Agency in the amount to which the Agency is entitled pursuant to its ownership interest in Catawba Unit 2, and to mitigate potential adverse economic effects on

Notes (continued)

the Agency and the participants from unscheduled outages of Catawba Unit 2. Correspondingly, the Agency bears risks resulting from unscheduled outages of any Catawba or McGuire Unit

ElectriCities of North Carolina, Inc.

ElectriCities of North Carolina, Inc (ElectriCities), organized as a joint municipal assistance agency under the General Statutes of North Carolina, is a public body and body corporate and politic created for the purpose of providing aid and assistance to municipalities in connection with their electric systems and to joint agencies, such as the Agency The Agency has entered into a management agreement with ElectriCities Under the current management agreement, ElectriCities is required to provide all personnel and personnel services necessary for the Agency to conduct its business in an economic and efficient manner

Industry Restructuring Developments and Related Uncertainties

Federal regulations have been passed which encourage wholesale competition among utility and non-utility power producers Similar regulations are contemplated for retail competition at both the federal and state level However, because of other states' experiences with deregulation, momentum has slowed significantly in North Carolina.

In 1997, the North Carolina General Assembly created the "Study Commission on the Future of Electric Service in North Carolina" (Study Commission) The Study Commission is comprised of 30 members, representing lawmakers, the North Carolina municipal, cooperative, and private electric utilities, electric consumers, the environmental community, and electric power marketers. The Study Commission is charged with examining the cost, adequacy, availability, and pricing of electric rates and service in North Carolina to determine whether legislation is necessary to assure an adequate and reliable source of electricity and economical, fair, and equitable rates for all consumers of electricity in North Carolina

After much discussion and negotiations, the Study Commission presented a report to the General Assembly in May 2000 which included recommendations for full retail choice no later that January 1, 2006 with fifty percent of each power supplier's customer load having the option of retail choice on January 1, 2005 The report indicated that the Study Commission would then make recommendations on how to address other aspects of deregulation such as stranded costs recovery, the Agency's debt, consumer protection, environment and alternative energy, tax laws, transmission and distribution, and any other areas which need to be addressed

In early 2001, the Study Commission determined that because of California's circumstances, North Carolina would take a "go slow" attitude toward deregulation No recommendations were made to the General Assembly during 2001 and none are anticipated in 2002

Because the Study Commission does not intend to make any recommendation to the General Assembly during 2002, and because the General Assembly is not bound by the work of the Study Commission, and because other entities are able to propose legislation on this issue, the Agency cannot predict whether there will be any legislative initiatives, what the results of legislative initiatives will be, or whether any such legislation will become law

The Board of Commissioners of the Agency, in conjunction with the Board of Directors of ElectriCities of North Carolina, Inc , has developed a strategic plan to address deregulation In addition, the Agency periodically reviews its regulatory assets and the impact of recovering such assets on Agency rates Also, the Agency's management and Board are participating in the deregulation debate, both on the national and state levels

For further discussion about deregulation and the possible effects on rates and deferred expenses, see Note D

B. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The accounts of the Agency are maintained on the accrual basis, in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission, and are in conformity with accounting principles generally accepted in the United States of America (GAAP) The Agency has adopted the principles promulgated by the Governmental Accounting Standards Board (GASB) and Statement of Financial Accounting Standard (SFAS) No 71 "Accounting for the Effects of Certain Types of Regulation," as amended. This standard allows utilities to capitalize or defer certain costs and/or revenues based upon the Agency's ongoing assessment that it is probable that such items will be recovered through future revenues.

In the future, issues of competitive market forces and restructuring in the electric utility industry might require the reduction in the carrying value of the Agency's regulatory assets unless appropriate action is taken to

Notes (continued)

assure the recovery of these regulatory assets, even in a market environment.

Financial Reporting

Under GASB Statement No. 20, "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting," the Agency has adopted the option to apply Financial Accounting Standards Board (FASB) statements and interpretations that do not conflict with or contradict GASB pronouncements

Electric Plant in Service

All expenditures associated with the development and construction of the Agency's ownership interest in the Catawba station, including interest expense net of investment income on funds not yet expended, have been recorded at original cost and are being depreciated on a straight-line basis over the average composite life of each unit's assets. At December 31, 2001, the remaining composite average life for Catawba's assets was 18 years. Original costs of major classes of the Agency's electric plant in service at December 31, 2001 and 2000 are shown in the chart at right.

Construction Work in Progress

All expenditures related to capital additions are capitalized as construction work in progress until such time as they are completed and transferred to Electric Plant in Service. No interest is capitalized on capital additions. Depreciation expense is recognized on these items after they are transferred

Nuclear Fuel

All expenditures related to the purchase and construction of nuclear fuel cores are capitalized until such time as the cores are placed in the reactor. No interest is capitalized on fuel cores When placed in the reactor, they are amortized and charged to fuel expense on the units of production method. Amounts are removed from the books upon disposal of the spent nuclear fuel. Nuclear fuel expense includes a provision for estimated spent nuclear fuel disposal costs which is being collected currently from members. Amortization of nuclear fuel costs includes estimated disposal costs of $6,544,000 and $6,357,000 for the years ended December 31, 2001 and 2000, respectively.

The Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the Department of Energy's (DOE) uranium enrichment plants. Nuclear plant licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services Duke makes the annual payment to DOE for the Catawba station and bills the co-owners monthly for their proportionate share. The Agency's payments to Duke were approximately $870,000 and $843,000 in 2001 and 2000, respectively, and were recorded as fuel expense.

Under provisions of the Nuclear Waste Policy Act of 1982, Duke, on behalf of all co-owners of the Catawba station, has entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent nuclear fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and Duke's contract with the DOE. In 1998, Duke, on behalf of all co-owners, filed a claim with the United States Court of Federal Claims against the DOE for damages arising out of the DOE's failure to begin accepting the spent nuclear fuel Claimed damages are intended to recover costs incurred and to be incurred as a result of the DOE's partial material breach of its

Electric Plant in Service ($000s)	*December 31,* *2001*	*2000*
• Land	$ 19,768	$ 19,768
• Structures and improvements	384,096	389,198
• Reactor plant equipment	593,955	594,893
• Turbo generator units	165,145	165,145
• Accessory electric equipment	123,497	123,576
• Miscellaneous plant equipment	48,690	48,731
• Station equipment	10,959	10,959
• Unclassified	100,212	97,862
	1,446,322	1,450,132
• Accumulated depreciation	(601,818)	(562,787)
	$ 844,504	$ 887,345

Unclassified assets are in service but not yet classified to specific plant accounts.

Notes (continued)

contract, including costs associated with securing additional spent fuel storage capacity

Non-Utility Property and Equipment

Expenditures related to purchasing and installing an in-house computer, jointly owned with North Carolina Eastern Municipal Power Agency (NCEMPA), have been capitalized and are fully depreciated In addition, the Agency has purchased various computer equipment for its load management and telemetry programs, which are being depreciated over the estimated useful life of the equipment Also included are the land and administrative office building jointly owned with NCEMPA and used by both agencies and ElectriCities. The administrative office building is being depreciated over 37 1/2 years on a straight-line basis

Non-Utility Property and Equipment original costs at December 31, 2001 and 2000 are shown in the chart below.

Investments

The Agency implemented the provisions of GASB Statement No 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools," which requires investments in marketable debt securities to be reported at fair value.

Derivative Financial Instruments

In June 1998, the FASB issued SFAS No 133, "Accounting for Derivative Instruments and Certain Hedging Activities" (SFAS No 133). In June 2000, the FASB issued SFAS No 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS 133" (SFAS No 138) SFAS No. 133 and SFAS No 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. SFAS No 133 and SFAS No 138 are effective for all fiscal years beginning after June 30, 2000 The Agency adopted SFAS No. 133 and SFAS No 138 on January 1, 2001 In accordance with the transition provisions of SFAS No 133, the Agency recorded a cumulative-effect-adjustment of $7,350,000 in the statement of revenues and expenses to recognize at fair value all derivatives outstanding at that date

All derivatives are recognized on the balance sheet at their fair value estimated based on current market pricing models The Agency has not designated any of its derivatives as hedges Changes in the fair value of derivative instruments are reported in current-period revenues and expenses

For the year ended December 31, 2000, prior to the adoption of SFAS No. 133, the Agency entered into interest rate swap agreements For interest rate swaps, fair value which would be paid or received if the swap were terminated is accrued and recognized in "Net increase in fair value of investments and derivative financial instruments" and may change as market interest rates change. If a swap contract is terminated prior to its maturity, the gain or loss is recognized immediately.

The Agency has only limited involvement with derivative financial instruments In December 1999, the Agency entered into an interest rate swap agreement with a termination date of December 2009 The Agency's objective for entering into the interest rate swap agreement is to synthetically convert a portion of its fixed rate debt to variable rate debt over the life of the swap Under the fixed to variable interest rate swap, NCEMPA receives a fixed rate of 4.984% through December 2009, while paying a variable rate based on the BMA Municipal Swap Index Interest paid and received under the swap agreement increases and decreases, respectively, interest expense The net effect was to reduce interest expense by $4,674,000 and $1,706,000 in 2001 and 2000, respectively The notional amount of this agreement is $200,600,000

The fair value of the interest rate swap agreement was approximately $12,149,000 and $7,350,000 at December 31, 2001 and

Non-Utility Property and Equipment ($000s)	*December 31, 2001*	*2000*
• Land	$ 710	$ 710
• Structures and improvements	1,499	1,499
• Computer equipment	1,000	998
• Telemetry equipment	745	645
	3,954	3,852
• Accumulated depreciation	(1,846)	(1,672)
	$ 2,108	$ 2,180

2000, respectively. Current market pricing models were used to estimate the fair value of the interest rate swap agreement. The fluctuation in the fair value of the interest rate swaps was an increase of $4,799,000 in 2001 and is included in "Increase in fair value of investments and derivative financial instruments" in the statement of revenues and expenses

By using derivative instruments, the Agency exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of the derivative contract is positive, the counterparty owes the Agency, which creates repayment risk for the Agency When the fair value of a derivative contract is negative, the Agency owes the counterparty and, therefore, does not possess repayment risk. The Agency minimizes the credit or repayment risk by entering into transactions with high-quality counterparties.

Market risk is the adverse effect on the value of financial instruments that results from a change in interest rates The market risk associated with interest-rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

Decommissioning Costs

U S. Nuclear Regulatory Commission (NRC) regulations require that each licensee of a commercial nuclear power reactor furnish to the NRC certification of its financial capability to meet the costs of nuclear decommissioning at the end of the useful life of the licensee's facility. As a co-licensee of Catawba Unit 2, the Agency is subject to these requirements and therefore has furnished certification of its financial capability to fund its share of the costs of nuclear decommissioning of the Catawba Station.

To satisfy the NRC's financial capability regulations, the Agency established an external trust fund (the Decommissioning Trust) pursuant to a trust agreement with a bank. The Agency's certification of financial capability requires that the Agency make annual deposits to the Decommissioning Trust which, together with the investment earnings and amounts previously on deposit in the trust, are anticipated to result in sufficient funds being held in the Decommissioning Trust at the expiration of the current operating licenses for the Catawba Units (currently 2024 for Unit 1 and 2026 for Unit 2) to meet the Agency's share of decommissioning.

Estimates of the future costs of decommissioning the units are based on the most recent site specific study which was conducted in 1999. The Agency's portion of decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, is $355,690,000, stated in 1999 dollars.

The Decommissioning Trust is irrevocable and funds may be withdrawn from the trust solely for the purpose of paying the Agency's share of the costs of nuclear decommissioning Under the NRC regulations, the Decommissioning Trust is required to be segregated from Agency assets and outside the Agency's administrative control. The Agency is deemed to have incurred and paid decommissioning costs as deposits are made to the Decommissioning Trust. In addition to the Decommissioning Trust, certain reserve assets are anticipated to be available to satisfy the Agency's total decommissioning liability

Recently Issued Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) SFAS No. 143 requires the Agency to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets The Agency is required to adopt SFAS No 143 on January 1, 2003. The Agency will record a corresponding asset which will be depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Any such adjustments for changes in the estimated future cash flows will also be capitalized and amortized over the remaining life of the asset. Management is currently evaluating what impact, if any, SFAS No 143 will have on the Agency's financial statements.

In August 2001, the FASB issued SFAS No 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144) Effective for fiscal year 2002, SFAS No 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of". SFAS No. 144 states the required accounting for disposing of long-lived assets whether previously held and used or newly acquired, and broadens the presentation of discontinued operations to include more disposal transactions. The implementation of SFAS No. 144 is expected to have no material impact on the Agency's financial position or results of operations.

Notes (continued)

Nuclear Relicensing

In June 2001, Duke filed an application with the NRC to renew the operating license for the Catawba units.

Deferred Costs

Unamortized debt issuance costs, shown net of accumulated amortization of $13,205,000 and $11,161,000 at December 31, 2001 and 2000, respectively, are being amortized on the interest method over the term of the related debt. Costs of advance refundings of debt, shown net of accumulated amortization of $178,597,000 and $155,630,000 at December 31, 2001 and 2000, respectively, are deferred and amortized over the term of the debt issued on refunding. Deferred revenues and costs to be recovered from future billings to participants are not amortized but will be either refunded to or recovered from participants through future rates (See Note D)

Discounts on Bonds

Discounts (net of premiums) on bonds, shown net of accumulated amortization of $46,888,000 and $41,189,000, at December 31, 2001 and 2000 respectively, are amortized over the terms of the related bonds in a manner which yields a constant rate of interest.

Taxes

Income of the Agency is excludable from federal income tax under Section 115 of the Internal Revenue Code. Chapter 159B of the General Statutes of North Carolina exempts the Agency from property and franchise or other privilege taxes In lieu of North Carolina property taxes, the Agency pays an amount which would otherwise be assessed on the non-utility property and equipment of the Agency In lieu of a franchise or privilege tax, the Agency pays to North Carolina an amount equal to 3 22% of the gross receipts from sales of electricity to participants Electric utility property is located in South Carolina and subject to South Carolina property tax An electric power excise tax equal to 05% (5/10 mill) for each kilowatt-hour of electric power sold for resale within South Carolina is also paid

Statements of Cash Flows

For purposes of the statements of cash flows, operating cash consists of unrestricted cash included in the line item on the balance sheets "operating assets funds invested"

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates

Reclassifications

Certain 2000 amounts have been reclassified to conform with 2001 classifications The reclassifications had no effect on excess of revenues over expenses or retained earnings as previously reported

C. INVESTMENTS

The resolution authorizes the Agency to invest in 1) direct obligations of, or obligations of which the principal and interest are unconditionally guaranteed by the United States (U S), 2) obligations of any agency of the U S or corporation wholly owned by the U S , 3) direct and general obligations of the State of North Carolina or any political subdivision thereof whose securities are rated "A" or better, 4) repurchase agreements with the Bond Fund Trustee, Construction Fund Trustee, or any government bond dealer reporting to the Federal Reserve Bank of New York which mature within nine months from the date they were entered into and are collateralized by previously described obligations, and 5) bank time deposits evidenced by certificates of deposit and bankers' acceptances.

Bank time deposits may only be in banks with capital stock, surplus, and undivided profits of $20 000,000 or $50,000,000 for North Carolina banks and out-of-state banks, respectively, and the Agency's investments deposited in such banks cannot exceed 50% and 25%, respectively, of such banks' capital stock, surplus, and undivided profits

The resolution permits the Agency to establish official depositories with any bank or trust company qualified under the laws of North Carolina to receive deposits of public moneys and having capital stock, surplus, and undivided profits in excess of $20,000,000

All depositories must collateralize public deposits in excess of federal depository insurance coverage The Agency's depositories use the pooling method, a single financial institution collateral pool. Under the pooling method, a depository establishes a single escrow account on behalf of all governmental agencies. Collateral is maintained with an eligible escrow agent in the name of the State Treasurer of North Carolina based on an approved averaging method for demand

Notes (continued)

deposits and the actual current balance for time deposits less the applicable federal depository insurance for each depositor. Responsibility for sufficient collateralization of these excess deposits rests with the financial institutions that have chosen the pooling method. Because of the inability to measure the exact amount of collateral pledged for the Agency under the pooling method, the potential exists for under-collateralization. However, the State Treasurer enforces strict standards for each pooling method depository, which minimizes any risk of under-collateralization At December 31, 2001 and 2000 the Agency had $6,000 and $100,000, respectively, covered by federal depository insurance.

The Agency's investments are categorized to give an indication of the level of risk assumed by the Agency at year-end Category 1 includes investments that are insured or registered or for which the securities are held by the Agency or its agent in the Agency's name. Category 2 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its trust department or agent in the Agency's name. Category 3 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its safekeeping department or agent, but not in the Agency's name. All investments, except repurchase agreements, are considered Category 1. Repurchase agreements are considered Category 3. The Agency's investments are detailed in the chart below.

Investments ($000s)	*December 31, 2001*		*December 31, 2000*	
	Cost Basis	*Market Value*	*Cost Basis*	*Market Value*
• Repurchase agreements	$243,387	$243,387	$ 226,083	$ 226,083
• U.S. government securities	4,992	5,175	10,371	10,469
• U.S. government agencies	461,644	468,661	425,613	425,718
• Municipal bonds	26,313	27,492	26,220	27,241
• Collateralized mortgage obligations	74,861	75,948	149,480	150,251
	811,197	820,663	837,767	839,762
• Decommissioning Trust securities	117,544	128,263	103,588	119,757
• Operating cash	5	5	1	1
• Restricted cash	1	1	204	204
• Accrued interest	6,903	6,903	6,764	6,764
• Total funds invested	$935,650	$955,835	$ 948,324	$ 966,488
Consisting of:				
• Special funds invested		$341,078		$ 336,918
• Decommissioning Trust		128,263		119,769
• Operating assets		486,494		509,801
		$955,835		$ 966,488

In accordance with the provisions of the resolution, the collateral under the repurchase agreements is segregated and held by the trustee for the Agency

Costs to be Recovered from Future Billings to Participants ($000s)	Year Ended December 31, 2001	Year Ended December 31, 2000	Inception to December 31, 2001	Inception to December 31, 2000
• Net deferred interest	$ (161)	$ (741)	$153,689	$ 153,850
• Amortization of debt discount and issuance costs	7,743	7,583	88,782	81,039
• Depreciation	50,069	51,233	727,129	677,060
• Amortization of debt refunding costs	22,967	23,606	243,627	220,660
• Participant billing offsets	(57,639)	(56,213)	(748,187)	(690,548)
• Increase in fair value of investments and derivative financial instruments	(14,173)	(35,406)	(32,336)	(18,163)
• Training costs			6,696	6,696
	$ 8,806	$ (9,938)	$439,400	$ 430,594

Deferred Revenues ($000s)	Year Ended December 31, 2001	Year Ended December 31, 2000	Inception to December 31, 2001	Inception to December 31, 2000
• Net special funds (withdrawals)/deposits	$(44,977)	$(53,044)	$103,431	$ 148,408
• Restricted investment income	19,364	21,317	357,188	337,824
• Rate stabilization funds used for other than operations			(121,840)	(121,840)
• Special funds excess valuations			(2,946)	(2,946)
	$(25,613)	$(31,727)	$355,833	$ 361,446
Net Costs to be Recovered from Future Billings to Participants ($000s)	$ 34,419	$ 21,789		

D. COSTS TO BE RECOVERED FROM FUTURE BILLINGS TO PARTICIPANTS AND DEFERRED REVENUES

Rates for power billings to participants are designed to cover the Agency's debt requirements, operating funds, and reserves as specified by the resolution and power sales agreements. Straight-line depreciation and amortization are not considered in the cost of service calculation used to design rates. In addition, certain earnings on bond resolution funds are restricted to those funds and not available for operations. The differences between debt principal maturities (adjusted for the effects of premiums, discounts, and amortization of deferred gains and losses) and straight-line depreciation and amortization and interest income recognition are recognized as costs to be recovered from future billings to participants. Funds collected through rates for reserve accounts and restricted investment income are recognized as deferred revenues.

The Agency's present charges to the participants, together with planned withdrawals from the Rate Stabilization Fund and Supplemental Reserve Account, are sufficient to recover all of the Agency's current annual costs of the participants' bulk power needs. Each participant is required under the power sales agreements to set its rates for its customers at levels sufficient to pay all its costs of its electric utility system, including the Agency's charges for bulk power supply. All participants have done so.

In a deregulated electric utility industry, the participants can expect to have as their major competition the investor-owned utilities (IOUs) and rural electric cooperatives presently operating in North Carolina and power marketers and others that begin serving North Carolina retail customers after deregulation The participants' retail electric rates are higher, on average, than the retail electric rates of the IOUs currently serving North Carolina.

Agency studies indicate that in a market environment, the participants may not be able to charge rates sufficient to meet their obligations to the Agency as well as cover the costs of their distribution systems This would give rise to stranded investments of the Agency and the need for stranded investment recovery in a deregulated environment The Agency expects that the methods by which it will recover some or all of its stranded investments will come from the legislative initiatives discussed in Note A. However, no assurances can be given that the Agency will be able to recover, in part or in whole, these stranded investments.

All rates must be approved by the Board of Commissioners Rates are designed on an annual basis and are reviewed quarterly. If they are determined to be inadequate to cover the Agency's current annual costs, rates may be revised.

The recovery of outstanding amounts associated with costs to be recovered from future billings to participants will coincide with the retirement of the outstanding long-term debt of the Agency barring a change in regulation. A change in regulation could directly affect the recoverability of these costs, resulting in impairment of these assets and reexamination of these assets in accordance with SFAS No 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (SFAS No 121). The Agency follows the accounting requirements of SFAS No. 121. This statement requires the long-lived assets be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable This statement also imposes stricter criteria for regulatory assets by requiring that such assets be probable of future recovery at each balance sheet date. Upon adoption, and to date, SFAS No. 121 has had no effect on the Agency's financial position See discussions of SFAS No. 144 at Note B, *Recently Issued Pronouncements.*

E. BONDS

The Agency has been authorized to issue Catawba Electric Revenue Bonds (bonds) in accordance with the terms, conditions, and limitations of the resolution. The total to be issued is to be sufficient to pay the costs of acquisition and construction of the project, as defined, and/or for other purposes set forth in the resolution. Future refundings may result in the issuance of additional bonds

The following shows bond activity during 2001.

• Bonds Outstanding at December 31, 2000	$ 2,271,884,000
• Principal payments January 1, 2001	(59,448,000)
• Bonds Outstanding at December 31, 2001	$ 2,212,436,000

The various issues comprising the outstanding debt are as follows (in thousands of dollars):

	December 31, 2001	2000
• **Series 1985B**		
6% maturing in 2020 with annual sinking fund requirements beginning in 2018	$80,575	$80,575
• **Series 1988**		
Zero coupon priced to yield 7.5% to 7.6% maturing annually from 2002 to 2003	5,526	8,289
• **Series 1990**		
6.8% to 6.9% maturing annually from 2002 to 2003	4,515	5,680
Zero coupon priced to yield 6 75% maturing in 2004	3,670	3,670
7% maturing in 2014	10,225	10,225
	18,410	19,575

Notes (continued)

	December 31, 2001	2000
• **Series 1992**		
5.75% to 8% maturing annually from 2002 to 2011	$ 383,385	$ 421,350
Zero coupon priced to yield 6.55% to 6.7% maturing annually from 2008 to 2012	100,000	100,000
5.75% maturing in 2015 with annual sinking fund requirements beginning in 2013	191,030	191,030
6.25% maturing in 2017 with annual sinking fund requirements beginning in 2016	86,610	86,610
6.2% maturing in 2018	83,540	83,540
5.75% maturing in 2020 with annual sinking fund requirements beginning in 2019	123,990	123,990
6% Indexed Caps Bonds maturing in 2012	65,300	65,300
	1,033,855	1,071,820
• **Series 1993**		
4.1% to 5.5% maturing annually from 2002 to 2010	165,020	179,550
PARS/INFLOS maturing in 2012 with annual sinking fund requirements beginning in 2011 with linked interest rate of 5.5%	54,800	54,800
5% maturing in 2015 with annual sinking fund requirements beginning in 2013	103,050	103,050
5% maturing in 2018 with annual sinking fund requirements beginning 2016	91,680	91,680
PARS/INFLOS maturing in 2020 with annual sinking fund requirements beginning in 2018 with linked interest rate of 5.6%	70,000	70,000
	484,550	499,080
• **Series 1995A**		
5.1% to 5.2% maturing annually from 2007 to 2008	15,185	15,185
5.375% maturing in 2020 with annual sinking fund requirements beginning in 2019	64,255	64,255
	79,440	79,440
• **Series 1997A**		
Redeemed		2,805
5% to 5.125% maturing annually from 2009 to 2011	21,115	21,115
5.125% maturing in 2015 with a sinking fund requirement in 2012	19,235	19,235
5.125% maturing in 2017 with annual sinking fund requirements beginning in 2016	57,425	57,425
	97,775	100,580
• **Series 1998A**		
4.5% to 5.5% maturing annually from 2002 to 2015	33,150	33,370
5.125% maturing in 2017 with annual sinking fund requirements beginning in 2016	49,810	49,810
5% maturing in 2020 with annual sinking fund requirements beginning in 2018	45,405	45,405
	128,365	128,585

Notes (continued)

	December 31, 2001	December 31, 2000
• **Series 1999A**		
5.75% to 6% maturing annually from 2007 to 2010	$ 83,340	$ 83,340
• **Series 1999B**		
6.125% to 6 625% maturing annually from 2006 to 2010	54,035	54,035
6.375% maturing in 2013 with annual sinking fund requirements beginning in 2011	33,585	33,585
6.5% maturing in 2020 with annual sinking fund requirements beginning in 2014	112,980	112,980
	200,600	200,600
	2,212,436	2,271,884
Less: Current maturities of bonds	59,508	59,448
Unamortized discount	101,002	106,701
	$2,051,926	$2,105,735

The table on page 36 is a summary of debt service requirements for bonds outstanding at December 31, 2001 and reflects principal debt service included in the designated year's rates. In accordance with the resolution, these moneys are deposited into the Bond Fund for payment of the following year's current maturities. Current maturities of $59,508,000 at December 31, 2001 were collected through rates during 2001 and deposited monthly into the Bond Fund to make the January 1, 2002 principal payment.

The fair market value of the Agency's long-term debt was estimated using a yield curve derived from December 31, 2001 and 2000 market prices for similar securities Using these yield curves, market prices were estimated to call date, to par call date, and to maturity. The lowest of the three prices was used as the estimated market price for each individual maturity and the individual maturities were summed to arrive at a fair market value of $2,249,935,000 and $2,288,589,000 at December 31, 2001 and 2000, respectively.

Certain proceeds of the Series 1984 (subsequently paid at maturity or refunded), 1985B, 1988, 1990, 1992, 1993, 1995A, 1997A, 1998A, and 1999A bonds were used to establish trusts for advance refunding of $3,417,280,000 of previously issued bonds At December 31, 2001, $3,137,470,000 of these bonds have been redeemed. Under these Refunding Trust Agreements, obligations of, or guaranteed by, the United States have been placed in irrevocable Refunding Trust Funds maintained by the Bond Fund Trustee. The government obligations in the respective Refunding Trust Funds along with the interest earnings on such obligations, will be sufficient to pay all interest on the refunded bonds when due and to redeem all refunded bonds at various dates prior to their original maturities, in amounts ranging from par to a maximum redemption price of 102%. The monies on deposit in each Refunding Trust Fund, including the interest earnings thereon, are pledged solely for the benefit of the holders of the refunded bonds Since the establishment of each Refunding Trust Fund, the refunded bonds are no longer considered outstanding obligations of the Agency.

Interest on the bonds is payable semi-annually. Certain of the following bonds are subject to redemption prior to maturity at the option of the Agency, on or after the following dates at a maximum of 102% of the respective principal amounts:

• Series 1985B	January 1, 1996
• Series 1990	January 1, 2000
• Series 1992 and 1993	January 1, 2003
• Series 1995A	January 1, 2006
• Series 1997A	January 1, 2007
• Series 1998A	January 1, 2008
• Series 1999B	January 1, 2010

The bonds are special obligations of the Agency, payable solely from and secured solely by (1) project revenues (as defined by the resolution) after payment of project operating expenses (as defined by the resolution) and (2) other monies and securities pledged for payment thereof by the resolution

Debt Service Deposit Requirements for Bonds ($000s)

Year	Principal	Interest*	Total
• 2002	$ 64,323	$ 115,419	$ 179,742
• 2003	68,280	111,917	180,197
• 2004	70,665	108,211	178,876
• 2005	87,135	104,285	191,420
• 2006	93,075	98,483	191,558
• 2007	98,205	92,648	190,853
• 2008	102,565	88,509	191,074
• 2009	107,195	86,664	193,859
• 2010	112,500	81,834	194,334
• 2011	118,520	76,051	194,571
• 2012	125,165	69,795	194,960
• 2013	132,460	62,762	195,222
• 2014	139,775	55,208	194,983
• 2015	148,210	47,466	195,676
• 2016	156,655	39,039	195,694
• 2017	165,880	30,569	196,449
• 2018	176,010	20,598	196,608
• 2019	186,310	10,302	196,612
Total	$2,152,928	$1,299,760	$3,452,688

** Assumes a 4 97% interest rate for the 1999B SWAP*

The resolution requires the Agency to deposit into special funds all proceeds of bonds issued and all project revenues (as defined by the resolution) generated as a result of the Project Power Sales Agreements and Interconnection Agreement The purpose of the individual funds is specifically defined in the resolution

F. COMMITMENTS AND CONTINGENCIES

ElectriCities

The Agency has a contractual agreement with ElectriCities whereby ElectriCities provides, at cost, general management services to the Agency This agreement continues through December 31 2004, and is automatically renewed for successive three-year periods unless terminated by one year's notice by either party prior to the end of the contract term

For the years ended December 31, 2001 and 2000, the Agency paid ElectriCities $4,867,000 and $4,801,000, respectively

Insurance

The Price-Anderson Act limits the public liability for a nuclear incident at a nuclear generating unit to $9,540,000,000, which amount is to be covered by private insurance and agreements of indemnity with the NRC. Such private insurance and agreements of indemnity are carried by Duke on behalf of all co-owners of the station The terms of this coverage require the owners of all licensed facilities to provide up to $88,100,000 per year per unit owned (adjusted annually for inflation) in the event of any nuclear incident involving any licensed facility in the nation, with an annual maximum assessment of $10,000,000 per unit owned. If any such payments are required, the Agency would be liable for 37.5% of those payments applicable to the station.

Property damage insurance coverage presently available for the station has a maximum benefit limited to $2,750,000,000. Such available coverage has been obtained.

Catawba License Extension Project

In 1999, Duke requested approval of the expenditure of funds for a capital addition relating to Duke's seeking an extension of the NRC operating license for the Catawba Station. The Agency questioned the appropriateness of allocating any portion of the costs to the Agency in light of uncertainty regarding the potential effect of electric industry restructuring legislation which might be enacted Thus, the Agency disapproved the capital project in accordance with Section 2.2(F) of the Restated Operation and Fuel Agreements between Duke and the Agency

On January 11, 2002, the Board approved the capital project and authorized Duke to bill the Agency its proportionate share plus interest. On March 1, 2002, the Agency was billed $1,947,000 for its proportionate share of these costs through December 31, 2001. Such amount is reflected in CWIP and accounts payable at December 31, 2001.

At December 31, 2000, the Agency's unbilled proportionate share of this capital addition was $480,000, plus interest.

G. OTHER REVENUES

Other revenues include $333,000 and $6,497,000 in 2001 and 2000, respectively, which were received from Duke in settlement of arbitration issues.

Schedules of Changes

In Assets of Funds Invested ($000s)

	Funds Invested Jan 1, 2000	Power Billing Receipts	Investment Income	Disbursements
• Bond Fund				
Interest account	$ 55,537	$ 0	$ 1,894	$(119,925)
Reserve account	194,896		12,450	
Principal account	55,417		1,845	(55,138)
	305,850	0	16,189	(175,063)
• Reserve & Contingency Fund	20,390		2,154	
• Special Reserve Fund	1,082		68	
• Revenue Fund:				
Revenue account	26,830	220,533	417	3,081
Rate stabilization account	268,974		14,351	
	295,804	220,533	14,768	3,081
• Operating Fund				
Working capital account	19,876		5,972	(165,639)
Fuel account	89,576			
	109,452	0	5,972	(165,639)
• Supplemental Fund:				
Supplemental account	38,280	40,518	2,496	(11,955)
Supplemental reserve account	113,781		6,965	
	152,061	40,518	9,461	(11,955)
	$884,639	$261,051	$48,612	$(349,576)

Note. The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2001 and 2000, respectively

See accompanying Independent Auditors' Report

Schedules of Changes

In Assets of Funds Invested ($000s)

Transfers	Funds Invested Dec. 31, 2000	Power Billing Receipts	Investment Income	Disbursements	Transfers	Funds Invested Dec. 31, 2001
$ 125,090	$ 62,596	$ 0	$ 968	$(123,043)	$120,349	$ 60,870
(11,320)	196,026		12,227		(11,195)	197,058
57,659	59,783		911	(59,448)	58,369	59,615
171,429	318,405	0	14,106	(182,491)	167,523	317,543
(5,585)	16,959		1,906		895	19,760
(107)	1,043		57			1,100
(253,341)	(2,480)	230,849	559	28,921	(226,638)	31,211
(31,810)	251,515		12,741		(46,680)	217,576
(285,151)	249,035	230,849	13,300	28,921	(273,318)	248,787
178,189	38,398		4,991	(158,690)	147,257	31,956
(18,990)	70,586				(12,442)	58,144
159,199	108,984	0	4,991	(158,690)	134,815	90,100
(34,667)	34,672	31,085	1,478	(18,754)	(21,618)	26,863
(5,118)	115,628		6,622		(8,297)	113,953
(39,785)	150,300	31,085	8,100	(18,754)	(29,915)	140,816
$ 0	$844,726	$261,934	$42,460	$(331,014)	$ 0	$818,106

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2001 and 2000, respectively

See accompanying Independent Auditors' Report

Schedules of Revenues & Expenses

Per Bond Resolution and Other Agreements (\$000s)

	Year Ended December 31, 2001			Year Ended December 31, 2000		
	Project	*Supplemental*	*Total*	*Project*	*Supplemental*	*Total*
Revenues:						
Sales of electricity to participants	$ 228,752	$ 32,311	$ 261,063	$ 230,130	$ 31,791	$ 261,921
Sales of electricity to utilities	62,616		62,616	55,759		55,759
Other revenues	661	114	775	7,210	56	7,266
Rate stabilization fund withdrawal	36,679		36,679	45,850		45,850
Fund valuations	14,210		14,210	14,681		14,681
Supplemental Reserve Fund withdrawal		8,298	8,298		7,194	7,194
Investment revenue available						
for operations	21,562	1,536	23,098	24,732	2,563	27,295
	364,480	42,259	406,739	378,362	41,604	419,966
Expenses:						
Operation and maintenance	76,708		76,708	83,348		83,348
Nuclear fuel	16,505		16,505	17,286		17,286
Interconnection services						
Purchased power	24,577	25,189	49,766	24,271	21,459	45,730
Transmission and distribution		11,225	11,225		14,109	14,109
Other		113	113		134	134
	24,577	36,527	61,104	24,271	35,702	59,973
Administrative and general – Duke	21,676		21,676	22,367		22,367
Administrative and general – Agency	3,341	3,644	6,985	3,762	3,907	7,669
Miscellaneous Agency expense		923	923		815	815
Gross receipts and excise taxes	10,183	1,004	11,187	9,937	1,031	10,968
Property tax	12,518		12,518	12,920		12,920
Debt service	176,631	161	176,792	183,025	149	183,174
Special funds deposits:						
Decommissioning fund	4,233		4,233	4,238		4,238
Reserve and contingency fund	18,108		18,108	17,208		17,208
	22,341		22,341	21,446		21,446
	364,480	42,259	406,739	378,362	41,604	419,966
Excess of Revenues Over Expenses	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

Note The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2001 and 2000, respectively

See accompanying Independent Auditors' Report

Statistical Highlights

Ten Years at a Glance (Unaudited)

	2001	2000	1999	1998	1997
• Megawatt-hour Sales (MWh)	4,638,350	4,749,523	4,567,636	4,496,603	4,223,699
• Peak Billing Demand (kW)	856,577	894,324	882,083	842,892	853,384
• Operating Revenues	$324,454,000	$324,946,000	$347,476,000	$361,131,000	$367,130,000
• Excess of Revenues over Expenditures	$0	$0	$0	$0	$0
• Sales to Utilities (Revenues)	$62,616,000	$55,759,000	$85,097,000	$102,551,000	$119,698,000
• Average Monthly Power Purchases by Cities (MWh)	386,529	395,794	380,636	374,717	351,975
• Average Monthly Billings to Cities	$21,755,000	$21,827,000	$21,734,000	$21,439,000	$20,514,000

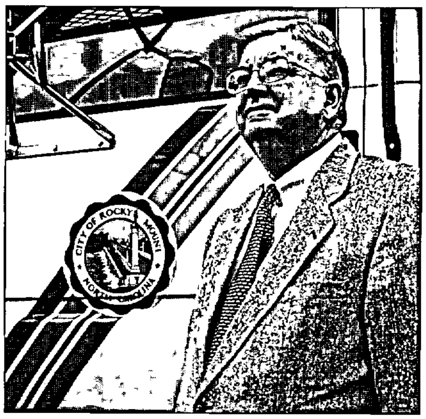
	1996	1995	1994	1993	1992
• Megawatt-hour Sales (MWh)	4,221,890	4,125,029	3,950,370	3,976,104	3,757,172
• Peak Billing Demand (kW)	829,245	803,615	752,717	788,060	740,847
• Operating Revenues	$375,577,000	$413,852,000	$540,695,000*	$443,511,000	$418,234,000
• Excess (Deficiency) of Revenues over Expenditures	$0	$0	$0	$3,121,000	$(5,799,000)
• Sales to Utilities (Revenues)	$134,453,000	$183,554,000	$237,153,000	$238,954,000	$234,625,000
• Average Monthly Power Purchases by Cities (MWh)	351,824	343,752	329,198	331,342	313,098
• Average Monthly Billings to Cities	$19,942,000	$19,077,000	$17,711,000	$17,046,000	$15,301,000

** Includes $91,005,000 received in settlement of arbitration issues.*

North Carolina Eastern **Municipal Power Agency**

20 Years of Power

Chairman Letter to Stakeholders



Frederick E. Turnage
Mayor, Rocky Mount
Chairman, NCEMPA

2001 might be described as a quiet year for North Carolina's electric utilities After so many years of studying deregulation, the issue was no longer our focus The Study Commission on the Future of Electric Service (SCFES) held only one meeting in 2001 and they decided to delay the proposed start date of deregulation

But 2001 was no time to sit idle Our cities continued the business of providing electricity and, as always, we made our scheduled debt payment on time and in full NCEMPA was also hard at work securing a contract for our supplemental power supply After going over more than 20 proposals with a fine-tooth comb, we determined CP&L provided the best opportunity and arrangements for our cities. This was a significant accomplishment as this contract represents nearly 30 percent of our total energy needs through 2006

Our cities were also keeping a close eye on proposed clean air legislation Any such plan would likely require capital improvements to our coal generating plants. We shepherded through privacy legislation that would ensure our customers' sensitive billing information would not get in the wrong hands We worked to see that our customers' needs were met and that our distribution systems were running well and efficiently

So as you can see, deregulation may have been put on hold in 2001, but our business was not Now we face more challenges We must continue our efforts to reduce costs and be more efficient to lessen the impact of any possible future rate increases We must continually improve and upgrade our systems and keep them in top running order. Past hurricanes have proven how important that is

2001 marked 20 years since our power agency officially became known as North Carolina Eastern Municipal Power Agency (NCEMPA) It also marks 20 years that NCEMPA has supplied all requirements power to all 32 participant cities. Initially, the eastern cities were split into two separate power agencies Our coming together back in 1981 made us stronger Today we remain united in our efforts to provide electricity to the citizens that call our communities home and to the businesses that help fuel our economy Local control and local operation of our own electric systems is a positive selling point and with a strong and unified group of electric cities, it always will be.

NCEMPA Leadership

2001 Board of Commissioners • 2001 Officers

Frederick E. Turnage
Chairman
Mayor, Rocky Mount

Mark S. Williams
Vice-Chairman
Town Manager, Wake Forest

Anne-Marie Knighton
Secretary-Treasurer
Town Manager, Edenton

Commissioners and Alternate Commissioners

Alternate commissioner's names appear in italics

• Apex
Mr. Bruce A Radford
Mr. J Michael Wilson

• Ayden
Mr Edwin L. Booth
Mayor Michael House

• Belhaven
Mr Timothy M. Johnson
Mr H Dewitt Hardison

• Benson
Mr Keith R. Langdon
Mayor Don H. Johnson

• Clayton
Mr. Robert J Ahlert
Mr Ronald E. Gurganus

• Edenton
Ms Anne-Marie Knighton
First Alternate Vacant
Mr. William A. Crummey

• Elizabeth City
Mr Steven L. Harrell
Mr Brett VanNieuwenhuise

• Farmville
Mr Richard N Hicks
Mr J Don Riddle

• Fremont
Commissioner Vacant
First Alternate Vacant
Mr Billy Harvey

• Greenville
Mr Charles E. Davis
Ms Nancy M. Jenkins
Mr Malcolm A Green

• Hamilton
Mr Herbert L. Everett
Mayor Donald G Matthews, III

• Hertford
Mr John Christensen
Mayor James Sidney (Sid) Eley

• Hobgood
Ms Stella Daugherty
Mayor Timothy D Purvis

• Hookerton
Mr R. Scott Spence
First Alternate Vacant

• Kinston
Mr Ralph A. Clark
Mr. Carey B Washburn
Mr Ronald D Wicker

• La Grange
Mr Mike Taylor
Mr Andy Hughes

• Laurinburg
Mr Joseph R. Huffman
Mayor Ann B Slaughter

• Louisburg
Mr. C. L Gobble
Ms Lois Brown Wheless
Mr Ray Patterson

• Lumberton
Mr Harry L. Ivey
Mr. W. Todd Powell
Mr J Franklin Price

• New Bern
Mr Ralph E Puckett
Mr Walter B Hartman, Jr.

• Pikeville
Mr Lyman Galloway
First Alternate Vacant

• Red Springs
Mr John McNeill
Mr T Wayne Horne

• Robersonville
Mr John H Pritchard, Jr
Mr John David Jenkins

• Rocky Mount
Mayor Frederick E. Turnage
Mr. Stephen W Raper

• Scotland Neck
Mayor Robert B Partin
First Alternate Vacant

• Selma
Commissioner Vacant
First Alternate Vacant

• Smithfield
Mr Peter T Connet
Mr Robert E. Tripp, III

• Southport
Mr. Paul D Fisher
Mr. Donald James "Jim" Henry

• Tarboro
Mr Samuel W Noble, Jr.
Mr Ricky C. Page
Mr James L. Alford

• Wake Forest
Mr Mark S Williams
Mr. Boyce C. Medlin

• Washington
Mr. R. L. Willoughby
Mr. Keith Hardt

• Wilson
Mr Edward A. Wyatt
Mr. Charles W Whitley, Jr
Mr Charles W Pittman, III

Electric System Participants

City/Town	Established	Revenues	Customers	% Ownership
• Apex	1917	2001 — $13,330,439 2000 — $13,108,892	9,154	0 706%
• Ayden	1916	2001 — $9,223,985 2000 — $8,571,413	3,695	1 134%
• Belhaven	1920	2001 — $2,315,095 2000 — $2,376,863	1,139	0 409%
• Benson	1913	2001 — $3,578,574 2000 — $3,467,178	1,800	0 577%
• Clayton	1913	2001 — $7,786,644 2000 — $7,119,224	4,082	0 745%
• Edenton	1908	2001 —Not Available 2000 —Not Available	3,899	1 596%
• Elizabeth City	1926	2001 — $24,393,759 2000 — $23,946,844	10,717	4 251%
• Farmville	1904	2001 — $5,090,104 2000 — $5,184,798	2,888	1 290%
• Fremont	1918	2001 — $1,266 695 2000 — $1 296,724	869	0 306%
• Greenville	1905	2001 —$118,998,891 2000 — $114,647,018	51 662	16 134%
• Hamilton	1922	2001 — $394,580 2000 — $396,043	254	078%
• Hertford	1915	2001 — $2,394,564 2000 — $2,051 028	1 271	0 412%
• Hobgood	1922	2001 — $437,477 2000 — $413,611	320	0 091
• Hookerton	1907	2001 — $659,808 2000 — $642,728	422	0 155%
• Kinston	1897	2001 — $36,469,351 2000 — $34,345,917	16,528	8 668%
• La Grange	1917	2001 — $2,442,179 2000 — $2,310,552	1,524	0 501%
• Laurinburg	1925	2001 — $12,807,234 2000 — $12,513,202	5,932	2 267%
• Louisburg	1906	2001 — $5,571,964 2000 — $5,378,600	1,940	0 858%
• Lumberton	1915	2001 — $23,295,394 2000 — $24,519,476	10,066	5 157%
• New Bern	1901	2001 — $39,062,539 2000 — $38,403,674	16,821	6 368%
• Pikeville	1918	2001 — $766,162 2000 — $807,931	527	0 205%
• Red Springs	1910	2001 — $3,322,061 2000 — $3,145,760	1 916	0 580%
• Robersonville	1919	2001 — $2,040,817 2000 — $2,142,427	1 220	0 507%
• Rocky Mount	1902	2001 — $62,597,012 2000 — $61,493,313	29,097	16 026%
• Scotland Neck	1903	2001 — $2,907,077 2000 — $3,241,434	1,630	0 576%
• Selma	1913	2001 — $5,425,610 2000 — $5,547,412	2,705	0 810%
• Smithfield	1912	2001 — $13,629,585 2000 — $12,015,061	4,568	2 006%
• Southport	1916	2001 — $4,241,594 2000 — $3,906,268	2,086	0 714%
• Tarboro	1897	2001 — $22,327,554 2000 — $21,736,954	5,797	4 743%
• Wake Forest	1909	2001 — $9,386,534 2000 — $8,649,414	4,900	0 726%
• Washington	1903	2001 — $23,867,256 2000 — $23,329,724	12,384	5 892%
• Wilson	1892	2001 — $93,548,632 2000 — $91,038,001	30 990	15 512%

Operational Highlights

Load Management and Power Operations

Agency staff and the participants successfully controlled load during each month's peak billing period for 2001. This success translated into power cost savings of over $36 million throughout the year. The Agency recommended load management an average of 12 hours per month, during approximately four days each month. NCEMPA participants and their customers shed an average of over 190 MW during the peak demand times each year. Load Side Generation is an integral part of this load shedding process with over 159 MW of generation noticed as of December 2001.

2001 saw the completion of a new 230 kW substation for Lumberton, substation equipment replacement for Louisburg and the development of new delivery points for Clayton, Greenville, and Wake Forest.

Agency and participant staff continued to develop communication alternatives for load management operations. The participants and their customers utilize more than 10 different paging companies Agency staff makes over 175,000 pages and e-mail communications through these different companies each year providing load management recommendations and information, in addition to over 3,000 direct telephone calls

Neighbors serving neighbors. One of the many advantages of living in a public power community is knowing the people who run your electric system. It means local control and friendly service.

Energy and Demand

The year's energy consumption was 6,787,351 MWh (including SEPA) and was below last years total of 6,944,631 MWh.

The highest monthly energy consumption for 2001 was 720,766 MWh, which was above the old record set in August 1999 of 717,270 MWh.

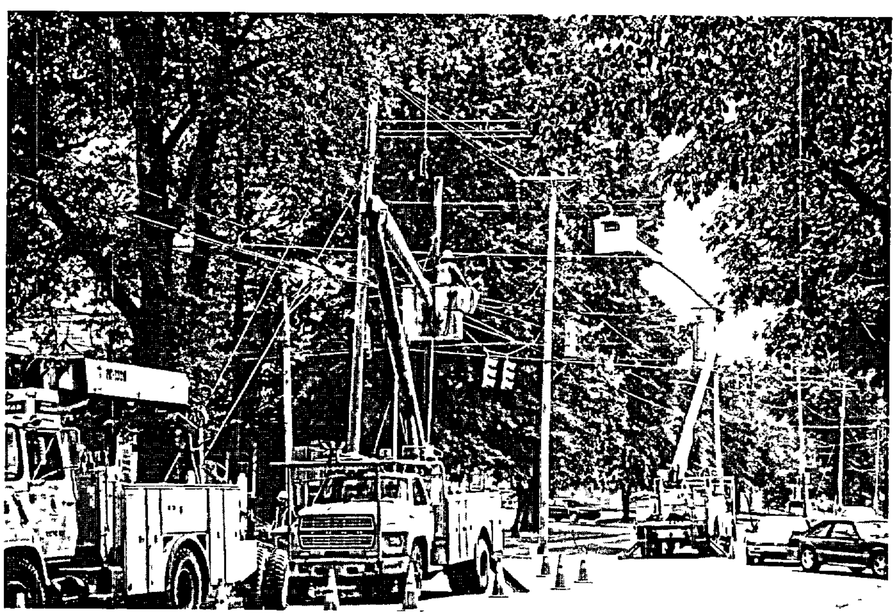
The highest Coincident Peak demand for 2001 (including SEPA) was 1,313 MW during August. This broke the old Coincident Peak record of 1,292 MW set in August 2000. The average Coincident Peak load factor (net of SEPA) for the year was 83 percent, a slight change from the 2000 average of 84 percent

The 2001 maximum Non-Coincident Peak demand (including SEPA) was 1,412 MW set in August This was up from the previous all time peak of 1,394 MW set in August 1999.

Environmental Regulations

Early in 2001 a coalition of environmental groups called upon the North Carolina General Assembly to take action to reduce air pollution from power plants. In April the bill approved by the Senate, the so called "Clean Smokestacks" bill, mandated pollution cuts of about 70 percent to be implemented in two stages by 2013. The bill calls for a 72 percent statewide reduction from 1998 levels of year-round nitrogen oxide (NO_x) emissions, a 73 percent statewide reduction of sulfur dioxide (SO_2) emissions, and a 60 percent incidental reduction of mercury. If the new Clean Smokestacks Act wins approval in the

Operational Highlights



TOP Top-notch customer service is a priority and one of the many benefits of living in a public power community BOTTOM Public power crews make repairs and replace older equipment to ensure citizens and businesses have a reliable source of power

full General Assembly, some pollution reductions may occur, others may not.

The state of North Carolina was not alone in its legislative activity and proposed reductions of power plant emissions On February 14, 2002, the Bush Administration announced the President's climate change policy, the "Clear Skies" initiative This proposal also establishes a general framework to reduce power plant emission of NO_x, SO_2, and mercury over the next 16 years and will require amending the Clean Air Act

As a coal-based power plant owner, both the State and Federal proposals present significant challenges and uncertainties for NCEMPA. As part of long range planning and budgeting to achieve environmental compliance, NCEMPA and CP&L have worked toward anticipating regulatory requirements by installing selective catalytic reduction (SCR) technology at Roxboro Unit 4 during 2001 This first SCR installed on an electric generating plant in North Carolina involves injecting ammonia into post-combustion flu gas as a catalyst, to break down NO_x into nitrogen and water, thereby curtailing the formation of ground level ozone

SCR technology, along with recently installed low NO_x burners, will minimize NO_x emissions from Roxboro Unit 4 by more than 85 percent and move the Agency well along to meeting both State and Federal compliance deadlines

Economic Development

The Eastern North Carolina cities continue their successful industrial recruitment and expansion of existing businesses NCEMPA members added 1,881 new jobs in

Operational Highlights

2001 to their communities with investments totaling $169,980,000. New load added to the Agency totaled more than 12 MW. NCEMPA staff and city representatives continue to work closely with the Department of Commerce and the Regional Partnerships to further the strategic load growth efforts in our communities

Advertising and direct mail was focused on automotive, pharmaceutical and medical instruments, boat manufacturers/suppliers, high technology, electronics, telecommunications, biotechnology, rubber and plastics, research and development, and software development industries. There were approximately 90 inquiries made which resulted in numerous site visits.

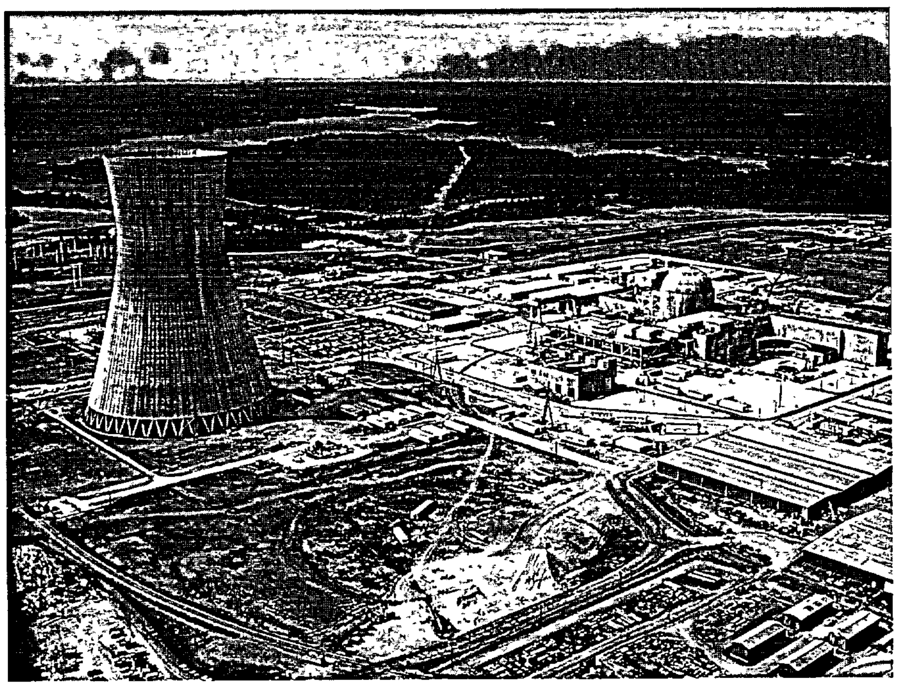
Marketing

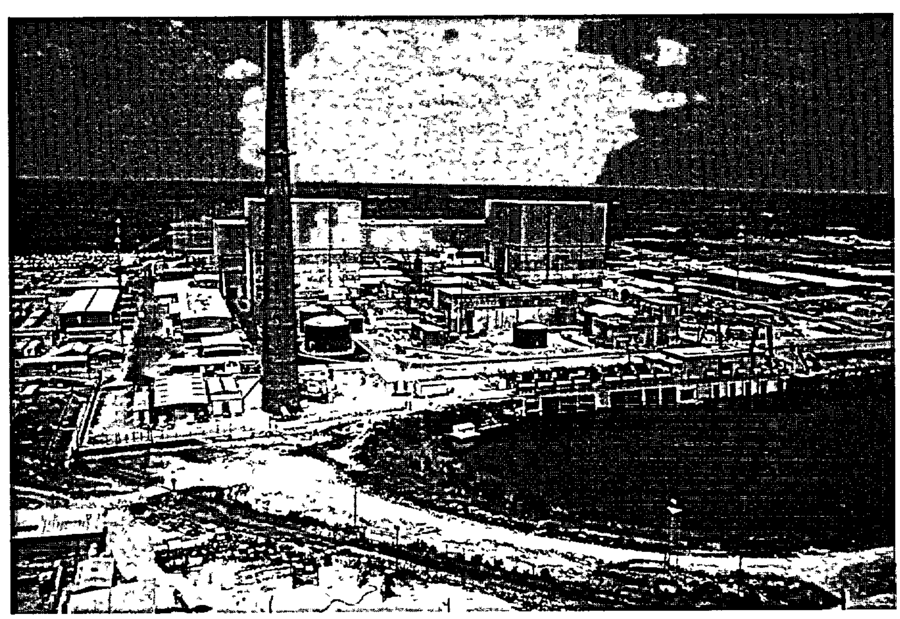
NCEMPA staff and city representatives continue to work closely with commercial and industrial customers to maximize the value of their energy dollars and reduce power costs

Our Energy Solutions Partner (ESP) alliance partners sold 36 projects in 2001. Our lead on-site generation partner sold 9,589 kW of new generation to NCEMPA customers Other ESP solutions include demand controllers for load management, turnkey lighting services, power quality services, and affordable training workshops.

Negotiations with CP&L

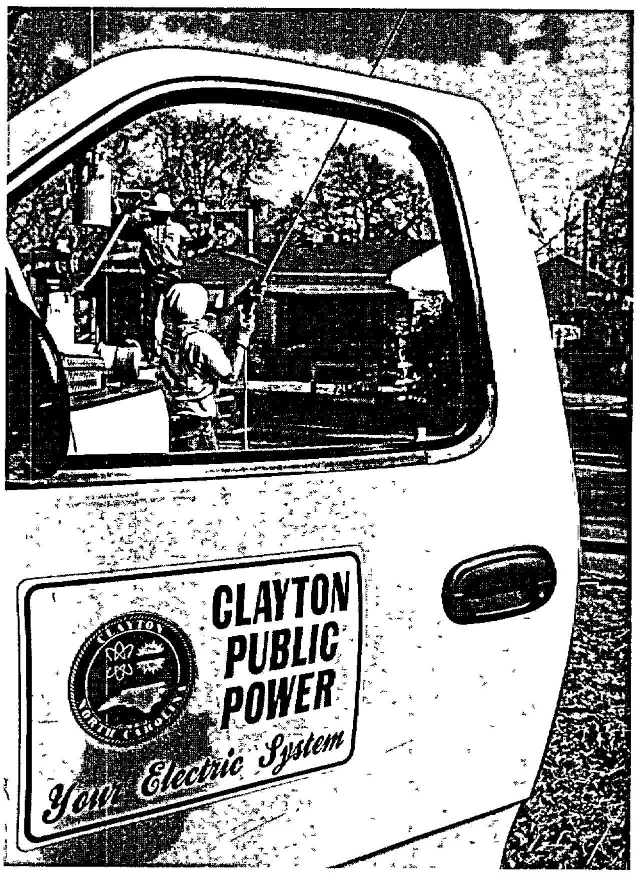
In October 2001, NCEMPA selected CP&L as its supplemental power supplier. NCEMPA's current contract with CP&L expires December 31, 2003 This new contract will expire December 31, 2006 The Agency put out a Request for Proposals





TOP· NCEMPA has 16 17% ownership in the Shearon Harris Nuclear Plant in Wake County. BOTTOM. NCEMPA has 18.33% ownership of the Brunswick Nuclear Plant in Southport.

Operational Highlights



Crews in Clayton make repairs to an electric line Clayton's electric system was established in 1913 Today the Johnston County town has more than 4,000 customers

in late 2000 looking for a new supplemental power contract They received 22 bids from 15 suppliers. The Agency worked through a short list of bidders in a lengthy process CP&L provided the best opportunity and best arrangement for the eastern cities

This contract means CP&L will provide additional power when needs exceed the capacity NCEMPA owns The contract represents 25 to 30 percent of NCEMPA's total energy needs or roughly 1,000 MW

Retail Billing

The Retail Billing program continued its steady growth in 2001 Tarboro added 13 customers and Kinston increased its participation by six At year-end, the program was serving 139 customers in 21 municipalities, and anticipating the addition of 11 new customers in Wake Forest Customer accounts are monitored and billing data dispatched on a timely basis so that the cities can process and prepare their retail bills. Cities who want to receive their billing information via email can do so, allowing them even faster access to their data To maintain data integrity, equipment failures are quickly detected and reported to the cities.

Plant Status

• ***Mayo Unit 1 and Roxboro Unit 4*** completed annual boiler inspection outages in the spring of 2001

• ***Brunswick Unit 2*** completed a 31-day refueling outage and generator rewind on March 27, which set a record for the shortest refuel outage for Unit 2 The unit operated continuously from March 27, providing 279 days of continuous service as of December 31, 2001

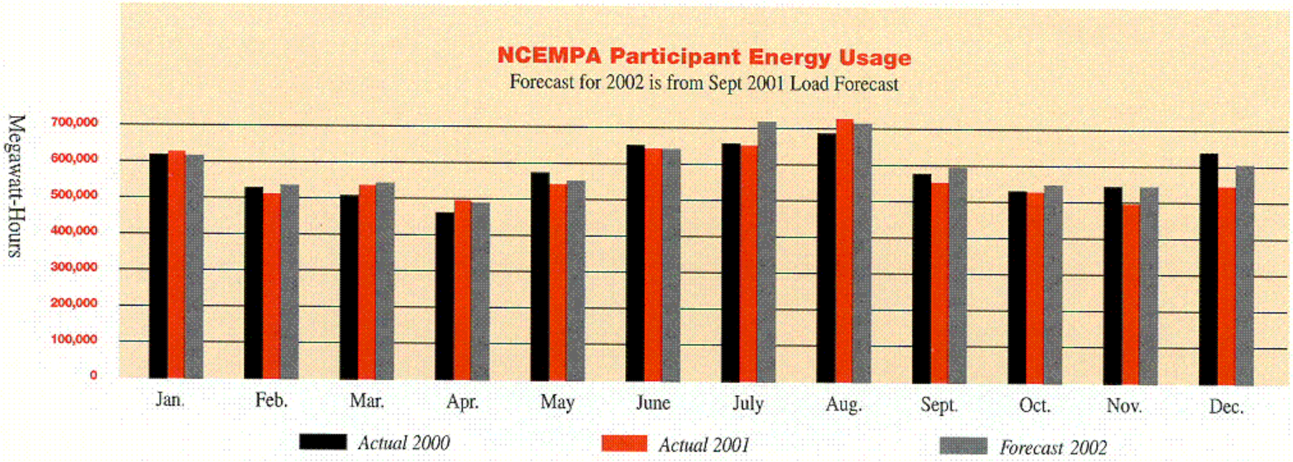
• ***Brunswick Unit 1*** passed the mark of providing 500 days of continuous service on August 6 and went on to set a new world record on October 27 for the longest continuous operating run for a GE boiling water reactor, breaking Unit 2's record of 581 days set in 1996. As of December 31, 2001, the unit had provided 647 days of continuous service.

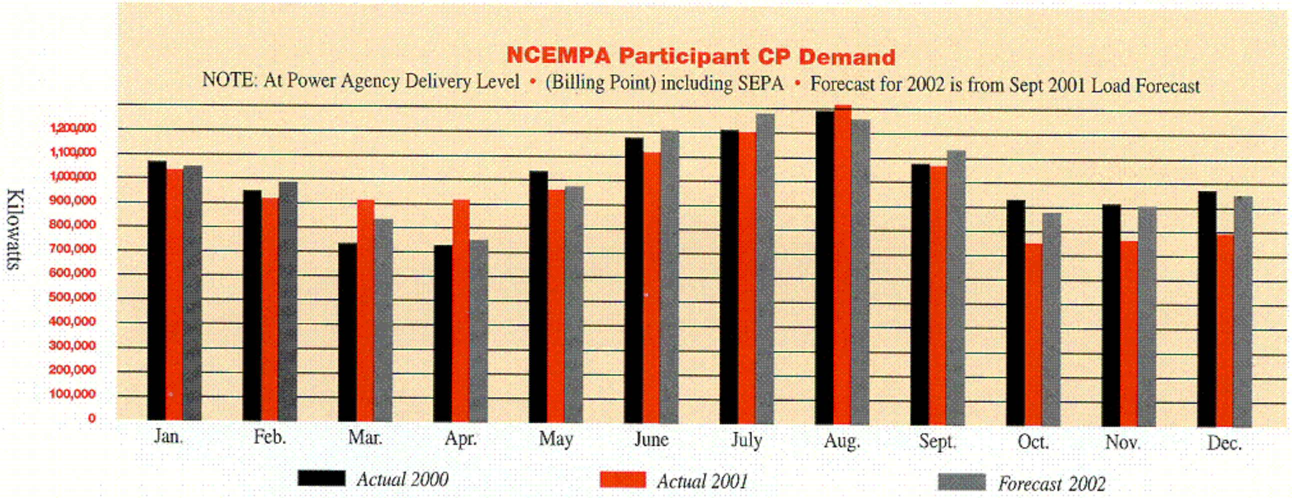
• ***Harris Unit 1*** completed its refueling and steam generator replacement outage on January 3, 2002 that began on September 22 A planned power uprate was also completed during this outage, which increased the generating capacity of the plant by 60 MW, for a total generating capacity of approximately 900 MW

Security

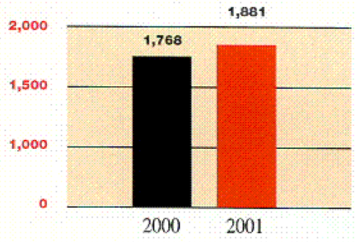
Following the terrorist attacks on the World Trade Center and the Pentagon on September 11, 2001, the focus shifted to another potential target The nation's nuclear power plants came under scrutiny about whether they could withstand a terrorist strike As a result of the events on 9/11, nuclear power plants across the United States have upgraded security measures. Under the contractual arrangement with NCEMPA, all issues of security are handled by CP&L CP&L is closely coordinating with federal, state and local authorities and has taken and continues taking appropriate steps to ensure safety and security at all the nuclear facilities in which NCEMPA has ownership

Operational **Highlights**

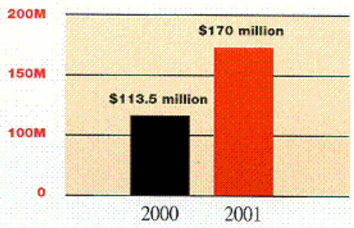




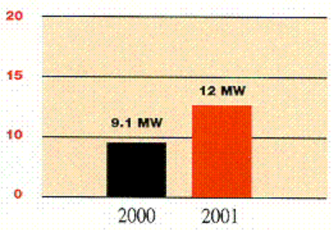
NCEMPA Economic Development



Number of New Jobs



Investments in Millions



Megawatt Growth

C02

Financial Information

Investment Portfolio Statistics

Earnings*

	Income	*Rate of Return*
• 2001	$29,575,000	5.80%
• 2000	$33,538,000	6.29%

Market Value as of 12/31*

	Value	*Average Maturity*
• 2001	$593,487,000	5.5 years
• 2000	$646,174,000	5.2 years

Transactions

	Number	*Amount*
• 2001	633	$8,222,276,000
• 2000	752	$6,948,522,000

** For Earnings and Market Value amounts include income from and market value of securities held in the decommissioning trust*

Debt Outstanding

Debt Outstanding 12/31

	Balance	*Weighted Average Interest Cost*
Fixed Rate Bonds		
• 2001	$3,204,444,000**	6.07%
• 2000	$3,271,245,000**	6.12%

NCEMPA Bond Reconciliation

• Bonds Outstanding 12/31/00		$3,271,245,000**
• Matured 1/1/01	-	66,801,000**
• Bonds Outstanding 12/31/01		$3,204,444,000**

NCEMPA Bonds Outstanding

• Series 1985G	$95,565,000
• Series 1986A	$4,495,000
• Series 1988A	$28,056,026**
• Series 1989A	$83,501,778**
• Series 1991A	$323,751,432
• Series 1993B	$1,470,520,000
• Series 1993C	$274,370,000
• Series 1993D	$78,300,000
• Series 1995A	$14,090,000
• Series 1996A	$252,495,000
• Series 1996B	$136,875,000
• Series 1997A	$29,185,000
• Series 1999A	$155,000,000
• Series 1999B	$116,725,000
• Series 1999C	$6,045,000
• Series 1999D	$135,470,000

*** Does not include $979,000 and $856,000 for 2001 and 2000, respectively, accrued on the balance sheet for current maturities of the Series 1988A Capital Appreciation Bonds or $3,634,000 and $1,148,000 for 2001 and 2000, respectively, for the Series 1989A Capital Appreciation Bonds.*

Independent Auditors' Report

We have audited the accompanying balance sheets of North Carolina Eastern Municipal Power Agency as of December 31, 2001 and 2000, and the related statements of revenues and expenses and changes in retained earnings, and cash flows for the years then ended. These financial statements are the responsibility of the Agency's management. Our responsibility is to express an opinion on these financial statements based on our audits

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North Carolina Eastern Municipal Power Agency as of December 31, 2001 and 2000, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in note B to the financial statements, the Agency changed its method of accounting for derivative financial instruments in 2001.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplementary information included in the Schedules of Revenues and Expenses per Bond Resolution and Other Agreements and Schedules of Changes in Assets of Funds Invested is presented for purposes of additional analysis and is not a required part of the basic financial statements Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

KPMG LLP

Raleigh, North Carolina • March 29, 2002

Balance Sheets

($000s)

Assets	December 31, 2001	2000
• Electric Utility Plant (Note C)		
Electric plant in service, net of accumulated depreciation of $679,007 and $629,605	$775,132	$ 788,041
Construction work in progress	9,143	20,213
Nuclear fuel, net of accumulated amortization of $38,319 and $35,612	31,424	28,587
	815,699	836,841
• Non-Utility Property and Equipment, net (Note C)	1,741	1,802
• Special Funds Invested (Notes D and H)		
Construction fund	2	6,304
Bond fund	371,681	378,804
Reserve and contingency fund	23,026	21,355
Decommissioning fund	4,868	4,748
Special reserve fund	1,033	1,029
	400,610	412,240
• Trust for Decommissioning Costs (Notes D and H)	93,315	86,034
• Operating Assets		
Funds invested (Notes D and H)		
Revenue fund	18,474	42,154
Operating fund	46,726	49,854
Supplemental fund	37,416	60,056
	102,616	152,064
Participant accounts receivable (Note E)	39,777	36,355
Fossil fuel inventory	6,009	3,831
Prepaid expenses	14,058	13,436
Derivative financial instruments (Note B)	15,681	
	178,141	205,686
• Deferred Costs.		
Unamortized debt issuance costs	35,957	37,851
VEPCO compensation payment (Note F)	7,773	8,162
Development costs	5,542	5,812
Costs of advance refundings of debt	420,205	454,828
Costs to be recovered from future billings to participants (Note G)	1,458,594	1,468,885
	1,928,071	1,975,538
	$3,417,577	$3,518,141

See accompanying notes to financial statements.

Balance Sheets

($000s)

	December 31, 2001	2000
Liabilities and Retained Earnings		
• Long-Term Debt.		
Bonds, net of unamortized discount (Note H)	$3,061,984	$3,119,976
• Special Funds Liabilities:		
Construction payables	1,838	1,821
Current maturities of bonds (Note H)	64,290	68,805
Accrued interest on bonds	92,961	99,922
	159,089	170,548
• Liability for Decommissioning Costs	90,589	79,350
• Operating Liabilities:		
Accounts payable	17,040	24,232
Accrued taxes	4,912	6,242
	21,952	30,474
• Deferred Revenues (Note G)	60,639	94,469
• Commitments and Contingencies (Notes J and K)		
• Retained Earnings	23,324	23,324
	$3,417,577	$3,518,141

Statements of Revenues & Expenses

And Changes in Retained Earnings ($000s)

	Year Ended December 31, 2001	2000
• Operating Revenues:		
Sales of electricity to participants	$ 424,881	$422,935
Sales of electricity to utilities	33 279	33,910
	458,160	456,845
• Operating Expenses:		
Operation and maintenance	38,644	38,934
Fuel	36,148	39,179
Power coordination services		
Purchased power	107,271	103,062
Transmission and distribution	14,210	16,103
Other	439	240
	121,920	119,405
Administrative and general	26,122	32,929
Amounts in lieu of taxes	3,857	3,991
Gross receipts tax	13,331	13,540
Depreciation and amortization	55,091	54,590
	295,113	302,568
• Net Operating Income	163,047	154,277
• Interest Charges (Credits)		
Interest expense	186,357	196,971
Amortization of debt refunding costs	34,622	35,821
Amortization of debt discount and issuance costs	3,557	3,514
Investment income	(23,293)	(23,470)
Net increase in fair value of investments and derivative financial instruments	(2,755)	(22,445)
Net interest capitalized		(2,146)
	198,488	188,245
• Net Costs to be Recovered From Future Billings to Participants (Note F)	23,539	33,968
• Revenues Over (Under) Expenses before Cumulative Effect of a Change in Accounting Principle	(11,902)	0
• Cumulative Effect of a Change in Accounting Principle (Note B)	11,902	
• Excess of Revenues Over Expenses	0	0
• Retained Earnings, Beginning of year	23,324	23,324
• Retained Earnings, End of year	$ 23,324	$ 23,324

See accompanying notes to financial statements.

Statements of Cash Flows

($000s)

	Year Ended December 31, 2001	2000
• Cash Flows from Operating Activities:		
Receipts from sales of electricity	$ 455,042	$ 454,166
Payments of operating expenses	(236,392)	(228,120)
Net cash provided by operating activities	218,650	226,046
• Cash Flows from Capital and Related Financing Activities:		
Interest paid	(188,704)	(197,663)
Debt discount and issuance costs paid	(69)	(82)
Additions to electric utility plant and non-utility property and equipment	(44,151)	(24,383)
Bonds retired or redeemed	(68,805)	(164,242)
Investment earnings receipts from construction fund	161	565
Net cash used for capital and related financing activities	(310,568)	(385,805)
• Cash Flows from Investing Activities:		
Sales and maturities of investment securities	8,136,174	6,892,469
Purchases of investment securities	(8,076,798)	(6,758,335)
Investment earnings receipts from non-construction funds	23,396	25,770
Net cash provided by investing activities	82,772	159,904
• Net (Decrease) Increase in Operating Cash	(146)	145
• Operating Cash, Beginning of year	148	3
• Operating Cash, End of year	$ 2	$ 148

See accompanying notes to financial statements

Statements of Cash Flows (continued)

($000s)

	Year Ended December 31, 2001	2000
• Reconciliation of Net Operating Income to Net Cash Provided by Operating Activities:		
Net Operating Income	$163,047	$154,277
Adjustments:		
Depreciation and amortization	55 091	54,590
Amortization of nuclear fuel	14,979	13,030
Changes in assets and liabilities		
Increase in participant accounts receivable	(3,422)	(2,645)
(Increase) decrease in fossil fuel stock	(2,178)	1,238
Increase in prepaid expenses	(622)	(1,237)
Decrease in deferred costs	659	659
(Decrease) increase in accounts payable	(7,574)	4,980
(Decrease) increase in accrued taxes	(1,330)	1,154
Total Adjustments	55,603	71,769
Net Cash Provided by Operating Activities	$218,650	$226,046

See accompanying notes to financial statements.

Notes to Financial Statements

Years Ended December 31, 2001 and 2000

A. GENERAL MATTERS

North Carolina Eastern Municipal Power Agency (Agency) is a joint agency organized and existing pursuant to Chapter 159B of the General Statutes of North Carolina to enable municipal electric systems, through the organization of the Agency, to finance, build, own, and operate generation and transmission projects The Agency is comprised of 32 municipal electric systems (participants) with interests ranging from 0.0783% to 16.1343%, which receive power from the Agency.

Initial Project

The initial project is comprised of the Agency's undivided ownership interests in three nuclear-fueled and two coal-fired generating units presently in commercial operation by Carolina Power & Light Company (CP&L). The initial project is financed under Power System Revenue Bond Resolution No R-2-82 (resolution) adopted by the Board of Commissioners (board) of the Agency. The resolution established special funds to hold proceeds from debt issuance, such proceeds to be used for costs of acquisition and construction of the initial project and to establish and maintain certain reserves. The resolution also established special funds into which initial project revenues from participants are to be deposited and from which initial project operating costs, debt service, and other specified payments are to be made.

The Agency entered into several agreements with CP&L which govern the purchase, ownership, construction, operation, and maintenance of the generating units in the initial project. Under these agreements, CP&L manages the construction and operation of the generating units in which the Agency has undivided ownership interests. Both CP&L and the Agency have the right to challenge the allocation of charges for a period extending to April 1 of the second year after which the challenged payment or adjustment was made.

During 2001, the Agency and CP&L finalized a new contract for supplemental power purchases by the Agency from CP&L from 2004 to 2006 Purchases under the new contract will replace purchases under the current contract and the Peaking Project Delay Agreement discussed later.

The Agency also entered into agreements with CP&L and Virginia Electric and Power Company (VEPCO) for the transmission of power to the Agency's participants. The Power Coordination Agreement (1981 PCA) obligates CP&L to purchase power from the Agency in specified percentages of the Agency's entitlement to such power from Harris Unit 1 (1987-2007).

The Agency entered into two power sales agreements with each of its participants for supplying the total electric power requirements of the participants in excess of Southeastern Power Administration (SEPA) allocations With the power generated from the initial project, together with supplemental purchases of power from CP&L, the Agency provides the total electric power requirements of its participants, exclusive of power allotments from SEPA. Under the Initial Project Power Sales Agreements, the Agency sells to the participants their respective shares of initial project output. The revenues received relative to the initial project are pledged as security for bonds issued under the resolution, after payment of initial project operating expenses. Each participant is obligated to pay its share of operating costs and debt service for the initial project. Under the Supplemental Power Sales Agreements, the Agency supplies each participant the additional power it requires in excess of that provided by output from the initial project and from SEPA.

Peaking Project Delay Agreement

In 1996, the Agency entered into an agreement with CP&L to delay the commercial operation of the Agency's peaking project (subsequently cancelled) until January 1, 2004. In return, CP&L will provide capacity and energy equal to the peaking project at a price comparable to what it would have cost to operate the peaking project during the delay period (June 1, 1998 to December 31, 2003). As mentioned previously, the Agency and CP&L entered into an agreement in 2001 for the replacement of the power provided under the Peaking Project Delay Agreement for 2004 to 2006

ElectriCities of North Carolina, Inc.

ElectriCities of North Carolina, Inc (ElectriCities), organized as a joint municipal assistance Agency under the General Statutes of North Carolina, is a public body and body corporate and politic created for the purpose of providing aid and assistance to municipalities in connection with their electric systems and to joint agencies, such as the Agency. The Agency entered into a management agree-

Notes (continued)

ment with ElectriCities Under the current management agreement with the Agency, ElectriCities is required to provide all personnel and personnel services necessary for the Agency to conduct its business in an economic and efficient manner

Industry Restructuring Developments and Related Uncertainties

Federal regulations have been passed which encourage wholesale competition among utility and non-utility power producers Similar regulations are contemplated for retail competition at both the federal and state level. However, because of other states' experiences with deregulation, momentum has slowed significantly in North Carolina.

In 1997, the North Carolina General Assembly created the "Study Commission on the Future of Electric Service in North Carolina" (Study Commission) The Study Commission is comprised of 30 members, representing law makers; the North Carolina municipal, cooperative, and private electric utilities; electric consumers, the environmental community, and electric power marketers The Study Commission is charged with examining the cost, adequacy, availability, and pricing of electric rates and service in North Carolina to determine whether legislation is necessary to assure an adequate and reliable source of electricity and economical, fair, and equitable rates for all consumers of electricity in North Carolina.

After much discussion and negotiations, the Study Commission presented a report to the General Assembly in 2000, which included recommendations for full retail choice no later that January 1, 2006, with fifty percent of each power supplier's customers load having the option of retail choice on January 1, 2005 The report indicated that the Study Commission would then make recommendations dealing with how to address other aspects of deregulation such as stranded costs recovery, the Agency's debt, consumer protection, environment and alternative energy, tax laws, transmission and distribution, and any other areas which need to be addressed.

In early 2001, the Study Commission determined that because of California's circumstances, North Carolina would take a "go slow" attitude toward deregulation. No recommendations were made to the General Assembly during 2001 and none are anticipated in 2002

Because the Study Commission does not intend to make any recommendations to the General Assembly during 2002, and because the General Assembly is not bound by the work of the Study Commission, and because other entities are able to propose legislation on this issue, the Agency cannot predict whether there will be any legislative initiatives, what the results of legislative initiatives will be, or whether any such legislation will become law

The Board of Commissioners of the Agency, in conjunction with the Board of Directors of ElectriCities of North Carolina, Inc , has developed a strategic plan to address deregulation In addition, the Agency periodically reviews its regulatory assets and the impact of recovering such assets on Agency rates. In addition, the Agency's management and Board are participating in the deregulation debate, both on the national and state level

For further discussion about deregulation and the possible effects on rates and deferred expenses, see Note G.

B. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The accounts of the Agency are maintained on the accrual basis, in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission, and are in conformity with accounting principles generally accepted in the United States of America (GAAP) The Agency has adopted the principles promulgated by the Governmental Accounting Standards Board (GASB) and Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended This standard allows utilities to capitalize or defer certain costs and/or revenues based upon the Agency's ongoing assessment that it is probable that such items will be recovered through future revenues

In the future, issues of competitive market forces and restructuring in the electric utility industry might require the reduction in the carrying value of the Agency's regulatory assets unless appropriate action is taken to assure the recovery of these regulatory assets, even in a market environment

Financial Reporting

Under GASB Statement No 20, "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting", the Agency has adopted the option to apply Financial Accounting Standards Board (FASB) statements and interpretations that do not conflict with or contradict GASB pronouncements

Electric Plant in Service

All direct and indirect expenditures associated with the development and construction of the Agency's undivided ownership interests in five of CP&L's generating units now in commercial operation, including interest expense net of investment earnings on funds not yet expended, have been recorded at original cost (plus acquisition adjustment) and are being depreciated (or amortized) on a straight-line basis over the composite average life of each unit's assets

At December 31, 2001, the remaining composite average life for Brunswick Units 1 and 2 was 7 years, Harris Unit 1 was 22 years, Roxboro Unit 4 was 12 years, and Mayo Unit 1 was 14 years

Construction Work in Progress

All expenditures associated with capital additions related to the Agency's undivided ownership interests in CP&L's generating units are capitalized as construction work in progress until such time as they are complete, at which time they are transferred to Electric Plant in Service. No interest is capitalized on capital additions. Depreciation expense is recognized on these items after they are transferred

Nuclear Fuel

All expenditures related to the purchase and construction of the Agency's undivided ownership interests in nuclear fuel cores at the nuclear units are capitalized until such time as the cores are placed in the reactor. No interest is capitalized on fuel cores. When placed in the reactor, they are amortized to fuel expense on the units of production method Nuclear fuel expense includes a provision for estimated disposal costs, which is being collected currently from participants Amortization of nuclear fuel costs in 2001 and 2000 includes a provision of $3,434,000 and $3,453,000, respectively, for estimated disposal costs.

The Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the Department of Energy's (DOE) uranium enrichment plants. Nuclear plant licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. CP&L makes the annual payment to DOE for the Brunswick and Harris units and bills the Agency for their proportionate share. The Agency's payments to CP&L were approximately $756,000 and $742,000 in 2001 and 2000, respectively, and were recorded as fuel expense.

Under provisions of the Nuclear Waste Policy Act of 1982, CP&L, on behalf of CP&L and the Agency, has entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent nuclear fuel in 1998, the year provided by the Nuclear Waste Policy Act and CP&L's contract with the DOE. CP&L, on behalf of all co-owners, along with other utilities, have taken steps to force the DOE to take spent nuclear fuel. To date, the courts have rejected these attempts While some utilities have filed actions for damages in the United States Court of Federal Claims, CP&L has not yet taken such action.

The Agency stores all spent fuel within its facilities. With certain modifications and additional Nuclear Regulatory Commission (NRC) approval, the Agency's spent fuel storage facilities are sufficient to handle all spent fuel generated by all of the Agency's nuclear generating units through the expiration of their current operating licenses In 1998, CP&L submitted a license amendment application to the NRC requesting NRC approval to activate and begin using the additional spent fuel storage at the Harris Plant. In December 2000, CP&L received such permission from the NRC.

Non-Utility Property and Equipment

All expenditures related to purchasing and installing an in-house computer, jointly owned with North Carolina Municipal Power Agency Number 1 (NCMPA1), have been capitalized and are fully depreciated Also included are the land and administrative office building jointly owned with NCMPA1 and used by both agencies and ElectriCities. The administrative office building is being depreciated over 37 1/2 years on a straight-line basis

Investments

The Agency has implemented the provisions of GASB Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools," which requires investments to be reported at fair value.

Derivative Financial Instruments

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133, "Accounting for Derivative Instruments and Certain Hedging Activities" (SFAS No 133). In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain

Notes (continued)

Hedging Activities, an Amendment of SFAS 133" (SFAS No. 138) SFAS No. 133 and SFAS No 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values SFAS No 133 and SFAS No. 138 are effective for all fiscal years beginning after June 30, 2000. The Agency adopted SFAS No 133 and SFAS No 138 on January 1, 2001 In accordance with the transition provisions of SFAS No. 133, the Agency recorded a cumulative-effect-adjustment of $11,902,000 in the statement of revenues and expenses to recognize at fair value all derivatives outstanding at that date.

All derivatives are recognized on the balance sheet at their fair value estimated based on current market pricing models The Agency has not designated any of its derivatives as hedges Changes in the fair value of derivative instruments are reported in current-period revenues and expenses

For the year ended December 31, 2000, prior to the adoption of SFAS No 133, the Agency entered into interest rate swap agreements For interest rate swaps, fair value which would be paid or received if the SWAP were terminated is accrued and recognized in "net increase in fair value of investments and derivative financial instruments" and may change as market interest rates change If a swap contract is terminated prior to its maturity, the gain or loss is recognized immediately.

The Agency has only limited involvement with derivative financial instruments In June of 1999 and January of 2000, the Agency entered into two identical interest rate swap agreements with termination dates of June 14, 2009 and December 31, 2009, respectively. The Agency's objective for entering into these interest rate swap agreements is to synthetically convert a portion of its fixed rate debt to variable rate debt over the life of the swaps Under these fixed to variable interest rate swaps, NCEMPA receives a fixed rate of 4 67% and 5 03%, respectively, through the termination dates, while paying a variable rate based on the BMA Municipal Swap Index Interest paid and received under the swap agreements increases and decreases, respectively, interest expense The net effect was to reduce interest expense $6,409,000 and $2,067,000 in 2001 and 2000, respectively The notional amount of each of these agreements is $155,000,000 and $136,970,000, respectively

The fair value of the two interest rate swap agreement was approximately $15,681,000 and $11,902,000 at December 31, 2001 and 2000, respectively Current market pricing models were used to estimate the fair value of the interest rate swap agreements The fluctuation in the fair value of the interest rate swaps was an increase of $3,779,000 in 2001 and is included in "Increase in fair value of investments and derivative financial instruments" in the statement of revenues and expenses.

By using derivative instruments, the Agency exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract When the fair value of the derivative contract is positive, the counterparty owes the Agency, which creates repayment risk for the Agency When the fair value of a derivative contract is negative, the Agency owes the counterparty and, therefore, does not possess repayment risk. The Agency minimizes the credit or repayment risk by entering into transactions with high-quality counterparties

Market risk is the adverse effect on the value of financial instruments that results from a change in interest rates. The market risk associated with interest-rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken

Decommissioning Costs

NRC regulations require that each licensee of a commercial nuclear power reactor furnish to the NRC certification of its financial capability to meet the costs of nuclear decommissioning at the end of the useful life of the licensee's facility As a co-licensee of Brunswick Units 1 and 2 and Harris Unit 1, the Agency is subject to the NRC's financial capability regulations, and therefore has furnished certification of its financial capability to fund its share of the costs of decommissioning those units

To satisfy the NRC's financial capability regulations, the Agency established an external trust fund (Decommissioning Trust) pursuant to a trust agreement with a bank The Agency's certification of financial capability requires that the Agency make annual deposits to the Decommissioning Trust which, together with the investment earnings and amounts previously on deposit in the trust, are anticipated to result in sufficient funds being held in the Decommissioning Trust at the expiration of the current operating licenses for the units (currently 2014 for Brunswick Unit 2, 2016 for Brunswick Unit 1, and 2026 for Harris Unit 1) to meet the Agency's share of decommissioning Estimates of the future costs of decommissioning the units are based on the most recent site specific study which was conducted in 1998 The Agency's portion of decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, is $67,242,000 for Brunswick Unit 1, $67,040,000 for Brunswick Unit 2, and $63,287,000 for Harris, all stated in 1998 dollars

The Decommissioning Trust is irrevocable, and funds may be withdrawn from the trust solely for the purpose of paying the Agency's share of the costs of nuclear decommissioning. Under the NRC regulations, the Decommissioning Trust is required to be segregated from Agency assets and outside the Agency's administrative control. The Agency is deemed to have incurred and paid decommissioning costs as amounts are deposited to the Decommissioning Trust. In addition to the Decommissioning Trust, certain reserve assets are anticipated to be available to satisfy the Agency's total decommissioning liability

The Agency determined that it was necessary to fund decommissioning costs associated with the non-nuclear portion of the Brunswick plant which fell outside the NRC requirements Therefore, it also deposits to the Decommissioning Fund, separate from deposits required to the Decommissioning Trust.

Recently Issued Pronouncements

In June 2001, the FASB issued SFAS No 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires the Agency to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of assets The Agency is required to adopt SFAS No 143 on January 1, 2003 The Agency will record a corresponding asset which will be depreciated over the life of the asset Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Any such adjustments for changes in the estimated future cash flows will also be capitalized and amortized over the remaining life of the asset. Management is currently evaluating what impact, if any, SFAS No. 143 will have on the Agency's financial statements.

In August 2001, the FASB issued SFAS No 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No 144). Effective for fiscal year 2002, SFAS No. 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes SFAS No 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of". SFAS No. 144 states the required accounting for disposing of long-lived assets whether previously held and used or newly acquired, and broadens the presentation of discontinued operations to include more disposal transactions The implementation of SFAS No 144 is expected to have no material impact on the Agency's financial position or results of operations

Fossil Fuel Inventory

Fossil fuel inventory includes fossil fuel stock and EPA Clean Air Act Allowances. Fossil fuel stock and EPA Clean Air Act Allowances are each stated at average cost.

Deferred Costs

Deferred costs are shown net of accumulated amortization Unamortized debt issuance costs at December 31, 2001 and 2000, shown net of accumulated amortization of $12,961,000 and $11,067,000, respectively, are being amortized on the interest method over the term of the related debt. Development costs, shown net of accumulated amortization of $5,825,000 and $5,555,000 at December 31, 2001 and 2000, respectively, are being amortized on a straight-line basis over the forty-year life of the initial project. Costs of advance refundings of debt at December 31, 2001 and 2000, shown net of accumulated amortization of $286,036,000 and $251,414,000, respectively, are deferred and are amortized over the term of the debt issued on refunding Costs to be recovered from future billings to participants and deferred revenues are not amortized but will be either recovered from or refunded to participants through future rates (see Note G)

Discounts on Bonds

Discounts on bonds (net of premiums) at December 31, 2001 and 2000 shown net of accumulated amortization of $14,026,000 and $12,342,000, respectively, are amortized over the terms of the related bonds in a manner which yields a constant rate of interest.

Notes (continued)

Taxes

Income of the Agency is excludable from income subject to federal income tax under Section 115 of the Internal Revenue Code Chapter 159B of the General Statutes of North Carolina exempts the Agency from property and franchise or other privilege taxes In lieu of property taxes, the Agency pays an amount which would otherwise be assessed on the real and personal property of the Agency. In lieu of a franchise or privilege tax, the Agency pays an amount equal to 3 22% of the gross receipts from sales of electricity to participants

Statements of Cash Flows

For purposes of the statements of cash flows, operating cash consists of unrestricted cash included in the line item on the balance sheets "operating assets funds invested"

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates

Reclassifications

Certain 2000 amounts have been reclassified to conform with 2001 classifications. The reclassifications had no effect on excess of revenues over expenses or retained earnings as previously reported

C. ELECTRIC PLANT IN SERVICE, NON-UTILITY PROPERTY AND EQUIPMENT, AND ACQUISITION AND CONSTRUCTION PROGRAM

Initial Project

The Agency has commitments to CP&L in connection with capital additions for the initial project Current estimates indicate the Agency's portion of these costs for 2002 and 2003 will be approximately $34,000,000

There were no interest costs capitalized as part of the cost of initial project capital additions under construction during 2001 and 2000

The Agency's agreements with CP&L specify the purchase of undivided ownership interests in nuclear-fueled and coal-fired generating units, which comprise the initial project, presently in commercial operation as detailed in the table below.

On July 1, 2001, CP&L uprated Brunswick Unit 1 to 820 MW from 790 MW as a result of plant improvements The Agency's ownership entitlement increased from 144 8 MW to 150.3 MW

On January 1, 2002, CP&L uprated Harris Unit 1 to 900 MW from 860 MW as a result of plant improvements. The Agency's ownership entitlement increased from 139 1 MW to 145 5 MW

			Agency	
	Commercial Operation	*Maximum Net Dependable Capability*	*Ultimate Ownership*	*Megawatts*
• Coal-Fired Units				
Roxboro Unit 4	1980	700 MW	12.94%	90 6 MW
Mayo Unit 1	1983	745	16 17	120 5
Total Coal-Fired Capability				211 1
• Nuclear-Fueled Units				
Brunswick Unit 2	1975	790	18 33	144 8
Brunswick Unit 1	1977	820	18 33	150 3
Harris Unit 1	1987	900	16 17	145 5
Total Nuclear-Fueled Capability				440 6
Total of All Units				651.7 MW

Notes (continued)

The table at the right *(top)* shows planned uprates at the Brunswick units and the Agency's increase in entitlement as a result of the uprates

Unit	*Projected Date*	*Design MNDC Increase*	*Agency Share*
• Brunswick Unit 1	2003	41 MW	7.5 MW
• Brunswick Unit 2	2004	62 MW	11.3 MW
• Brunswick Unit 1	2005	107 MW	19.6 MW
• Brunswick Unit 2	2006	105 MW	19.3 MW

Peaking Project

Interest costs of $2,147,000 were capitalized as part of the cost of the peaking project in 2000, net of investment income on unexpended bond proceeds of $2,147,000 No interest was capitalized in 2001.

Electric Plant in Service

Original costs of major classes of the Agency's electric plant in service at December 31, 2001 and 2000 are shown in the table at the right *(middle)*.

Electric Plant in Service ($000s)	*December 31,* *2001*	*2000*
• Land	$ 14,180	$ 14,180
• Structures and improvements	482,006	481,762
• Reactor plant equipment	410,283	378,417
• Turbo generator units	123,396	121,345
• Accessory electric equipment	174,213	173,869
• Miscellaneous plant equipment	50,720	50,304
• Other	28,026	27,792
• Unclassified	171,315	169,977
	1,454,139	1,417,646
• Accumulated depreciation	(679,007)	(629,605)
	$ 775,132	$ 788,041

Unclassified assets are in service but not yet classified to specific plant accounts

Non-Utility Property and Equipment

Non-Utility Property and Equipment original costs at December 31, 2001 and 2000 are shown in the table at the right *(bottom)*.

Non-Utility Property and Equipment ($000s)	*December 31,* *2001*	*2000*
• Land	$ 710	$ 710
• Structures and improvements	1,491	1,491
• Computer equipment	605	551
	2,806	2,752
• Accumulated depreciation	(1,065)	(950)
	$1,741	$1,802

D. INVESTMENTS

The resolution authorizes the Agency to invest in 1) direct obligations of, or obligations of which the principal and interest are unconditionally guaranteed by the United States (U.S.), 2) obligations of any Agency of the U.S or corporation wholly owned by the U.S , 3) direct and general obligations of the State of North Carolina or any political subdivision thereof whose securities are rated "A" or better, 4) repurchase agreements with a member of the Federal Reserve System which are collateralized by previously described obligations, and 5) bank time deposits evidenced by certificates of deposit and bankers' acceptances

Bank time deposits may only be in banks with capital stock, surplus, and undivided profits of $20,000,000 or $50,000,000 for North Carolina banks and out-of-state banks, respectively, and the Agency's investments deposited in such banks cannot exceed 50% and 25%, respectively, of such banks' capital stock, surplus, and undivided profits

The resolution permits the Agency to establish official depositories with any bank or trust company qualified under the laws of North Carolina to receive deposits of public moneys and having capital stock, surplus, and undivided profits aggregating in excess of $20,000,000

All depositories must collateralize public deposits in excess of federal depository insurance coverage The Agency's depositories use the pooling method, a single financial institution collateral pool Under the pooling method, a depository establishes a single escrow account on behalf of all governmental agencies Collateral is maintained with an eligible escrow agent in the name of the State Treasurer of North Carolina based on an approved averaging method for demand deposits and the actual current balance for time deposits less the applicable federal depository insurance for each depositor Responsibility for sufficient collateralization of these excess deposits rests with the financial institutions that have chosen the pooling method. Because of the inability to measure the exact amount of collateral pledged for the Agency under the pooling method, the potential exists for under-collateralization However, the State

Investments ($000s)

	December 31, 2001 *Cost Basis*	2001 *Market Value*	2000 *Cost Basis*	2000 *Market Value*
• Repurchase agreements	$107,148	$107,148	$259,353	$259,353
• U S government securities	7,987	8,280	19,967	20,114
• U S government agencies	313,771	317,511	168,068	169,739
• Municipal bonds	39,096	39,930	18,332	19,052
• Strips	9,232	9,064	15,304	15,280
• Collateralized mortgage obligations	17,366	18,239	76,476	76,602
	494,600	500,172	557,500	560,140
• Decommissioning Trust securities	88,311	93,315	77,080	86,034
• Operating cash	2	2	148	148
• Restricted cash	5	5	301	301
• Accrued interest	3,047	3,047	3,715	3,715
• Total funds invested	$585,965	$596,541	$638,744	$650,338
• Consisting of:				
Special funds invested		$400,610		$412,240
Decommissioning Trust		93,315		86,034
Operating assets		102,616		152,064
		$596,541		$650,338

Treasurer enforces strict standards for each pooling method depository, which minimizes any risk of under-collateralization At December 31, 2001 and 2000, the Agency had $7,000 and $435,000, respectively, covered by federal depository insurance.

The Agency's investments are categorized to give an indication of the level of risk assumed by the Agency at year-end. Category 1 includes investments that are insured or registered or for which the securities are held by the Agency or its agent in the Agency's name. Category 2 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its trust department or agent in the Agency's name. Category 3 includes uninsured and unregistered investments for which the securities are held by the broker or dealer, or by its safekeeping department or agent, but not in the Agency's name. All investments except repurchase agreements are considered Category 1 Repurchase agreements are considered Category 3. The Agency's investments are detailed in the table at the left.

In accordance with the provisions of the resolution, the collateral under the repurchase agreements is segregated and held by the trustee for the Agency.

E. PARTICIPANT ACCOUNTS RECEIVABLE

At December 31, 2001, there were $8,532,000 of unbilled receivables associated with the peaking project benefits versus peaking project participant credits. This receivable will be recovered from the peaking project participants in 2002 and 2003.

F. VEPCO COMPENSATION PAYMENT

The VEPCO compensation payment represents compensation to VEPCO for early termination of service for those participants previously served by VEPCO This payment of $15,515,000 and the related capitalized interest of $33,000 were deferred and are being amortized on a straight-line basis over 40 years, the expected life of the initial project. The balance at December 31, 2001 and 2000 is net of accumulated amortization of $7,775,000 and $7,386,000, respectively.

G. COSTS TO BE RECOVERED FROM FUTURE BILLINGS TO PARTICIPANTS AND DEFERRED REVENUES

Rates for power billings to participants are designed to cover the Agency's debt requirements, operating funds, and reserves as specified by the resolution and power sales agreements. Straight-line depreciation and amortization are not considered in the cost of service calculation used to design rates. In addition, certain earnings on bond resolution funds are restricted to those funds and not available for operations The differences between debt principal maturities (adjusted for the effects of premiums, discounts, and amortization of deferred gains and losses) and straight-line depreciation and amortization and interest income recognition are recognized as costs to be recovered from future billings to participants Funds collected through rates for reserve accounts and restricted investment income are recognized as deferred revenues.

The Agency's present charges to the participants, together with planned withdrawals from the Rate Stabilization Fund and Special Supplemental Reserve Account, are sufficient to recover all of the Agency's current annual costs of the participants' bulk power needs Each participant is required under the power sales agreements to set its rates for its customers at levels sufficient to pay all its costs of its electric utility system, including the Agency's charges for bulk power supply. All participants have done so.

In a deregulated electric utility industry, the participants can expect to have as their major competition the investor-owned utilities (IOUs) and rural electric cooperatives presently operating in North Carolina and power marketers and others that begin serving North Carolina retail customers after deregulation The participants present retail electric rates are higher, on average, than the present retail electric rates of the IOUs currently serving North Carolina

Agency studies indicate that in a market environment, the participants may not be able to charge rates sufficient to meet their obligations to the Agency as well as cover the costs of their distribution systems. This would give rise to stranded investments of the Agency and the need for stranded investment recovery in a deregulated environment The Agency expects that the methods by which it will recover some or all of its stranded investments will come from the legislative initiatives discussed in Note A However, no assurances can be given that the Agency will be able to recover, in part or in whole, these stranded investments

All rates must be approved by the Board of Commissioners. Rates are designed on an annual basis and are reviewed quarterly. If

Notes (continued)

they are determined to be inadequate to cover the Agency's current annual costs, rates may be revised

The recovery of outstanding amounts associated with costs to be recovered from future billings to participants will coincide with the retirement of the outstanding long-term debt of the Agency barring a change in regulation. A change in regulation could directly affect the recoverability of these costs, resulting in impairment of these assets and reexamination of these assets in accordance with SFAS No 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" This statement requires the long-lived assets be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. This statement also imposes stricter criteria for regulatory assets by requiring that such assets be probable of future recovery at each balance sheet date. Upon adoption, and to date, SFAS No 121 has had no effect on the Agency's financial position. See discussions of SFAS No 144 at Note B, *Recently Issued Pronouncements*

H. BONDS

The Agency has been authorized to issue Power System Revenue Bonds (bonds) in accordance with the terms, conditions, and limitations of the resolution The total to be issued is to be sufficient to pay the costs of acquisition and construction of the project, as defined, and/or for other purposes set forth in the resolution Future refundings may result in the issuance of additional bonds

Costs to be Recovered from Future Billings to Participants ($000s)	*Year Ended December 31,*		*Inception to December 31,*	
	2001	*2000*	*2001*	*2000*
• Deferred interest expense	$ (3,465)	$ 300	$ 656,319	$ 659,784
• Amortization of debt discount and issuance costs	3,557	3,514	55,827	52,270
• Net increase in fair value of investments and derivative financial instruments	(14,657)	(22,445)	(26,251)	(11,594)
• Depreciation and amortization	55,091	54,589	827,251	772,428
• Amortization of debt refunding costs	34,622	35,821	411,049	376,427
• Participant billing offsets	(85,439)	(75,002)	(510,955)	(425,516)
• New project negotiation and Harris Plant litigation costs			45,086	45,086
	$ (10,291)	$ (3,223)	$1,458,594	$1,468,885
Deferred Revenues ($000s)				
• Net special funds withdrawals	$ (35,503)	$(37,062)	$ (135,284)	$ (99,781)
• Restricted investment income	1,673	(129)	218,334	216,661
• Rate stabilization funds used for other than operations			(21,839)	(21,839)
• Special funds valuations			(572)	(572)
	$ (33,830)	$(37,191)	$ 60,639	$ 94,469
Net Costs to be Recovered From Future Billings to Participants ($000s)	$ 23,539	$ 33,968		

Notes (continued)

The following chart shows bond activity during 2001.

• Bonds Outstanding at December 31, 2000	$3,273,249,000
Principal payments January 1, 2001 (Includes $2,004,000 in appreciated value on the Series 1988 A and 1989 A Capital Appreciation serial bonds.)	(68,805,000)
Transfer from Accrued Interest to Current Maturities of Bonds to reflect the appreciated value of the Series 1988 A and 1989 A Capital Appreciation serial bonds due January 1, 2002	4,613,000
• Bonds Outstanding at December 31, 2001	$3,209,057,000

The various issues comprising the outstanding debt are as follows (in thousands of dollars):

	December 31,	
	2001	*2000*
• Series 1985 G		
5.75% maturing in 2016 with annual sinking fund requirements beginning in 2012	$ 95,565	$ 95,565
• Series 1986 A		
5% maturing in 2017 with annual sinking fund requirements beginning in 2015	4,495	4,495
• Series 1988 A		
7 6% capital appreciation serial bonds maturing in 2002	1,525	1,951
6% maturing in 2026 with annual sinking fund requirements beginning in 2025	27,510	27,510
	29,035	29,461
• Series 1989 A		
7.35% to 7.4% capital appreciation serial bonds maturing annually from 2002 to 2003	8,246	6,612
7.5% maturing in 2010 with annual sinking fund requirements beginning in 2009	28,890	28,890
5 5% maturing in 2011	50,000	50,000
	87,136	85,502
• Series 1991 A		
Redeemed		3,260
7.875% maturing in 2002	14,255	14,255
6 25% maturing annually from 2003 to 2006	33,020	33,020
6.3% to 6.4% capital appreciation serial bonds maturing annually from 2004 to 2006	2,376	2,376
6 5% maturing in 2012 with annual sinking fund requirements beginning in 2007	14,910	14,910
6 5% maturing in 2017 with annual sinking fund requirements beginning in 2013	99,755	99,755
6 5% maturing in 2018	28,755	28,755
5.75% maturing in 2019	130,680	130,680
	323,751	327,011

Notes (continued)

	December 31, 2001	December 31, 2000
• **Series 1993 B**		
5.5% to 7.25% maturing annually from 2002 to 2009	$ 391,950	$ 396,655
6.25% maturing in 2012 with annual sinking fund requirements beginning in 2010	247,815	247,815
6% maturing in 2013	40,345	40,345
6% structured yield curve notes maturing in 2014	55,550	55,550
5.5% maturing in 2017 with annual sinking fund requirements beginning in 2015	146 625	146,625
6% maturing in 2018	97,790	97,790
5 5% maturing in 2021 with annual sinking fund requirements beginning in 2019	194,510	194,510
6% maturing in 2022	157,740	157,740
6 25% maturing in 2023	105,210	105,210
6% maturing annually from 2025 to 2026	32,985	32,985
	1,470,520	1,475,225
• **Series 1993 C**		
5% to 7% maturing annually from 2002 to 2007	195,815	225,515
7% maturing in 2013 with annual sinking fund requirements beginning in 2010	20,965	20,965
5% maturing in 2021 with annual sinking fund requirements beginning in 2014	57,590	57,590
	274,370	304,070
• **Series 1993 D**		
5 875% maturing in 2013 with annual sinking fund requirements beginning in 2012	27,605	27,605
5 875% maturing in 2014	15,960	15,960
5 6% maturing in 2016 with annual sinking fund requirements beginning in 2015	34,735	34,735
	78,300	78,300
• **Series 1995 A**		
Redeemed		2,520
5 125% maturing in 2012	14,090	14,090
	14 090	16,610
• **Series 1996 A**		
Redeemed		21,530
5 5% to 6% maturing annually from 2004 to 2006	105,805	105,805
5 6% maturing in 2010	1,060	1,060
5 625% to 5 7% maturing annually from 2012 to 2016	83,320	83,320
5 625% maturing in 2024 with annual sinking fund requirements beginning in 2017	62,310	62,310
	252,495	274,025

Notes (continued)

	December 31, 2001	December 31, 2000
• **Series 1996 B**		
6% maturing in 2006	$ 12,000	$ 12,000
5 8% maturing in 2016	22,920	22,920
5 875% maturing in 2021 with annual sinking fund requirements beginning in 2020	101,955	101,955
	136,875	136,875
• **Series 1997 A**		
Redeemed		840
5 375% maturing in 2024	29,185	29,185
	29,185	30,025
• **Series 1999 A**		
5.2% maturing in 2010	5,000	5,000
5.75% maturing in 2026 with annual sinking fund requirements beginning in 2023	150,000	150,000
	155,000	155,000
• **Series 1999 B**		
5 55% to 5 7% maturing annually from 2014 to 2017	40,035	40,035
5.75% maturing in 2024	76,690	76,690
	116,725	116,725
• **Series 1999 C (Federally Taxable)**		
6 48% to 7.05% maturing annually from 2002 to 2007	6,045	7,390
• **Series 1999 D**		
5 45% maturing in 2004 with annual sinking fund requirements beginning in 2001	4,500	6,000
6% maturing in 2009 with annual sinking fund requirements beginning in 2005	7,470	7,470
6 45% maturing in 2014 with annual sinking fund requirements beginning in 2010	7,500	7,500
6.7% maturing in 2019 with annual sinking fund requirements beginning in 2015	35,875	35,875
6.75% maturing in 2026 with annual sinking fund requirements beginning in 2020	80,125	80,125
	135,470	136,970
	3,209,057	3,273,249
Less: Current maturities of bonds	64,290	68,805
Unamortized discount	82,783	84,468
	$3,061,984	$3,119,976

Notes (continued)

Debt Service Deposit Requirements for Bonds ($000s)

Year	*Principal*	*Interest**	*Total*
• 2002	$ 78,776	$ 187,602	$ 266,378
• 2003	82,097	180,312	262,409
• 2004	90,116	175,969	266,085
• 2005	98,368	170,910	269,278
• 2006	118,070	164,053	282,123
• 2007	127,100	156,327	283,427
• 2008	133,595	147,468	281,063
• 2009	118,230	141,072	259,302
• 2010	133,315	135,296	268,611
• 2011	140,711	127,329	268,040
• 2012	124,728	118,659	243,387
• 2013	142,164	111,295	253,459
• 2014	145,694	102,916	248,610
• 2015	148,180	94,610	242,790
• 2016	142,763	86,045	228,808
• 2017	144,855	77,664	222,519
• 2018	156,650	68,849	225,499
• 2019	168,735	59,806	228,541
• 2020	178,235	50,169	228,404
• 2021	170,830	40,188	211,018
• 2022	175,625	29,869	205,494
• 2023	168,015	19,153	187,168
• 2024	77,675	9,506	87,181
• 2025	80,240	4,842	85,082
Total	$3,144,767	$2,459,909	$5,604,676

** Assumes a 4 56% interest rate for the 1999A SWAP and a 5 17% interest rate for the 1999D SWAP*

At left is a summary of the debt service deposit requirements for bonds outstanding at December 31, 2001. This table reflects principal debt service included in the designated year's rates In accordance with the resolution, these moneys are deposited into the Bond Fund for payment of the following year's current maturities Current maturities of $64,290,000 at December 31, 2001 were collected through rates during 2001 and deposited monthly into the Bond Fund to make the January 1, 2002 principal payment

The fair market value of the Agency's long-term debt was estimated using the Dobbins Scale The individual maturities were priced and summed to arrive at a fair market value of $3,244,498,000 and $3,360,260,000 at December 31, 2001 and 2000, respectively.

Certain proceeds of the Series 1985 G, 1986 A, 1988 A, 1989 A, 1991 A, 1993 B, 1993 C, 1995 A, 1996 A, 1997 A, 1999 A, 1999 B, and 1999 C bonds, were used to establish trusts for refunding $4,297,580,000 of previously issued bonds. At December 31, 2001, $3,852,350,000 of these bonds have been redeemed Under these Refunding Trust Agreements, obligations of, or guaranteed by, the United States have been placed in irrevocable Refunding Trust Funds maintained by the Bond Fund Trustee The government obligations in the Refunding Trust Funds, along with the interest earnings thereon, will be sufficient to pay all interest when due on the refunded bonds and to redeem all refunded bonds still outstanding at December 31, 2001 at various dates prior to or on their original maturities at par The monies on deposit in the Refunding Trust

Funds, including the interest earnings thereon, are pledged solely for the benefit of the holders of the refunded bonds Since the establishment of each Refunding Trust Fund, the refunded bonds are no longer considered outstanding obligations of the Agency.

Interest on the bonds is payable semi-annually. Certain of the bonds are subject to redemption prior to maturity at the option of the Agency, on or after the following dates, at a maximum of 102 1/2% of the respective principal amounts·

- Series 1986 A — January 1, 1996
- Series 1988 A — January 1, 1998
- Series 1989 A — January 1, 1999
- Series 1991 A — January 1, 2002
- Series 1993 B, C, and D and Series 1985 G — January 1, 2003
- Series 1995 A — January 1, 2006
- Series 1996 A and B — January 1, 2007
- Series 1997 A — January 1, 2008
- Series 1999 A and B — January 1, 2009
- Series 1999 D — January 1, 2010

The bonds are special obligations of the Agency, payable solely from and secured solely by (1) revenues (as defined by the resolution) after payment of operating expenses (as defined by the resolution) and (2) other monies and securities pledged for payment thereof by the resolution.

The resolution requires the Agency to deposit into special funds all proceeds of bonds issued and all revenues (as defined by the resolution) generated as a result of the Initial Project Power Sales Agreements and the 1981 PCA. The purpose of the individual funds is specifically defined in the resolution

I. SURETY BOND

At December 31, 2001, the Agency had a $10,000,000 surety bond from an insurance company for the period June 13, 2001 to June 13, 2002 The term of the surety bond shall continue for consecutive one year terms unless written notice of termination is provided by the Agency or CP&L at least 60 days prior to the expiration of the then current term. In accordance with a 2001 agreement between the Agency and CP&L, the surety bond replaces a $12,900,000 letter of credit which expired on April 20, 2001, previously maintained by the Agency in accordance with the initial project agreements. The surety bond is for CP&L to call upon should the Agency fail to make full payment of its monthly obligations under the Operating and Fuel Agreement

On each anniversary date of the surety bond, with 60 days prior notification to the Agency, CP&L may require an increase in the amount of the surety bond, not to exceed $12,900,000

The Agency paid $112,000 for the surety bond in 2001 and paid quarterly commitment fees of $43,000 and $131,000 for 2001 and 2000, respectively, for the letter of credit.

J. COMMITMENTS

The Agency has a contractual agreement with ElectriCities whereby ElectriCities provides, at cost, general management services to the Agency. This agreement continues through December 31, 2004, and is automatically renewed for successive three-year periods unless terminated by one year's notice by either party prior to the end of any contract term.

For the years ended December 31, 2001 and 2000, the Agency paid ElectriCities $2,962,000 and $3,047,000, respectively

K. CONTINGENCIES

The Price-Anderson Act limits the public liability for a nuclear incident at a nuclear generating unit to $9,540,000,000, which amount is to be covered by private insurance and agreements of indemnity with the NRC. Such private insurance and agreements of indemnity are carried by CP&L on behalf of all co-owners of the initial project. The terms of this coverage require the owners of all licensed facilities to provide up to $88,100,000 per year per unit (adjusted annually for inflation) in the event of any nuclear incident involving any operating facility in the nation, with a maximum of $10,000,000 per year per unit owned in the event of more than one incident. The joint owners of a unit would be liable for the amount of any such assessment in proportion to their respective ownership interests.

The Price Anderson Act expires August 1, 2002. Although several renewal programs are before Congress, the final outcome cannot be predicted.

CP&L carries, for the benefit of the owners, property insurance on the various plants of the initial project. All risk coverage for the operating units ranges from $100,000,000 to $500,000,000 with a deductible of $1,000,000. In addition, nuclear liability insurance exists in the form and amount necessary to meet the financial requirements established by the NRC.

[illegible]

In Assets of Funds Invested ($000s)

	Funds Invested Jan 1, 2000	*Power Billing Receipts*	*Investment Income*	*Disbursements*
• Construction Fund				
Initial project construction account	$ 13,609	$ 0	$ 360	$ (7,457)
Peaking construction account	93,769		(734)	(93,034)
	107,378	0	(374)	(100,491)
• Bond Fund:				
Interest account	91,747		2,869	(192,418)
Reserve account	210,133		13,569	
Principal account	59,874		2,112	(59,787)
Peaking interest account	3,287		1	(3,285)
Peaking principal account	2,471		1	(2,472)
Peaking reserve account	7,008		8	(6,925)
	374,520	0	18,560	(264,887)
• Reserve & Contingency Fund				
Initial project account	22,759		2,392	(5,880)
Peaking account	705		(13)	(692)
	23,464	0	2,379	(6,572)
• Decommissioning Fund	3,915		281	
• Special Reserve Fund	1,093		68	
• Revenue Fund				
Revenue account	30,832	303,055	1,066	(4,221)
Peaking account	9,284	10,489	157	(3,030)
Rate stabilization account – CP&L	34,524		311	
Rate stabilization account – VEPCO	8,267		224	
	82,907	313,544	1,758	(7,251)
• Operating Fund:				
Working capital account	24,674		2,429	(110,758)
Fuel account	34,085			
	58,759	0	2,429	(110,758)
• Supplemental Fund				
Supplemental account	18,800	88,089	1,101	(97,378)
CP&L rate stabilization	29,448		1,861	
Special Supplemental Reserve		18,756	296	(31)
	48,248	106,845	3,258	(97,409)
	$700,284	$420,389	$28,359	$(587,368)

Note. The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2001 and 2000, respectively

See accompanying Independent Auditors' Report

Schedules of Changes

In Assets of Funds Invested ($000s)

Transfers	*Funds Invested Dec. 31, 2000*	*Power Billing Receipts*	*Investment Income*	*Disbursements*	*Transfers*	*Funds Invested Dec. 31, 2001*
$ (193)	$ 6,319	$ 0	$ 162	$ (6,479)	$ 0	$ 2
(1)	0					0
(194)	6,319	0	162	(6,479)	0	2
193,066	95,264		1,510	(192,450)	188,925	93,249
(11,129)	212,573		12,994		(15,620)	209,947
66,994	69,193		984	(68,805)	63,033	64,405
(3)	0					0
	0					0
(91)	0					0
248,837	377,030	0	15,488	(261,255)	236,338	367,601
1,961	21,232		1,937	(19,612)	19,128	22,685
	0					0
1,961	21,232	0	1,937	(19,612)	19,128	22,685
	4,196		238			4,434
(118)	1,043		57		(71)	1,029
(304,082)	26,650	327,716	815	247	(344,551)	10,877
(16,900)	0					0
(23,793)	11,042		28		(4,077)	6,993
(4,023)	4,468		72		(3,935)	605
(348,798)	42,160	327,716	915	247	(352,563)	18,475
108,162	24,507		1,829	(110,983)	106,703	22,056
(8,844)	25,241				(935)	24,306
99,318	49,748	0	1,829	(110,983)	105,768	46,362
22,920	33,532	54,050	1,162	(111,189)	58,217	35,772
(6,436)	24,873		1,058		(25,485)	446
(17,490)	1,531	40,294	354		(41,332)	847
(1,006)	59,936	94,344	2,574	(111,189)	(8,600)	37,065
$ 0	$561,664	$422,060	$23,200	$(509,271)	$ 0	$497,653

Note: The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2001 and 2000, respectively

See accompanying Independent Auditors' Report

Schedules of Revenues & Expenses

Per Bond Resolution and Other Agreements (\$000s)

	Year Ended December 31, 2001			*Year Ended December 31, 2000*		
	Initial Project	*Supplemental*	*Total*	*Initial Project*	*Supplemental*	*Total*
Revenues:						
Sales of electricity to participants	$332,419	$ 92,462	$424,881	$310,514	$112,421	$422,935
Sales of electricity to utilities	33,279		33,279	33,910		33,910
Rate stabilization fund withdrawal	8,012	25,485	33,497	27,816	6,435	34,251
Special funds valuations	4,084		4,084	19,496		19,496
Special supplemental reserve fund withdrawl		2,000	2,000			0
Other operating revenues	93		93	164	39	203
Investment revenue available for operations	20,303	1,579	21,882	24,237	1,620	25,857
	398,190	121,526	519,716	416,137	120,515	536,652
Expenses:						
Operation and maintenance	38,639	5	38,644	38,930	4	38,934
Fuel	36,148		36,148	34,179		34,179
Power coordination services:						
Purchased power	7,624	99,647	107,271	7,090	95,972	103,062
Transmission and distribution		14,210	14,210		16,103	16,103
Other		439	439		240	240
	7,624	114,296	121,920	7,090	112,315	119,405
Administrative and general – CP&L	19,188		19,188	25,671		25,671
Administrative and general – Agency	2,848	4,086	6,934	3,299	3,959	7,258
Amounts in lieu of taxes	3,857		3,857	3,991		3,991
Gross receipts tax	10,704	2,627	13,331	9,998	3,542	13,540
Letters of credit commitment fees and administrative costs	673		673	128		128
Debt service	248,633	162	248,825	263,025	1,044	264,069
Special funds deposits						
Revenue fund		350	350		(349)	(349)
Reserve and contingency fund	25,530		25,530	25,616		25,616
Decommissioning fund	4,316		4,316	4,210		4,210
	29,846	350	30,196	29,826	(349)	29,477
	398,190	121,526	519,716	416,137	120,515	536,652
Excess of Revenues Over Expenses	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

Note The schedule above has been prepared in accordance with the underlying Bond Resolution, and accordingly, does not reflect the change in the fair value of investments as of December 31, 2001 and 2000, respectively

See accompanying Independent Auditors' Report

Statistical Highlights

Ten Years at a Glance (Unaudited)

	2001	2000	1999	1998	1997
• Megawatt-hour Sales (MWh)	6,765,157	6,924,955	6,569,652	6,556,169	6,273,385
• Peak Billing Demand (kW)	1,284,897	1,265,241	1,217,221	1,190,030	1,185,129
• Operating Revenues	$458,160,000	$456,845,000	$445,358,000	$449,489,000	$446,742,000
• Excess (Deficiency) of Revenues over Expenditures	$0	$0	$0	($2,676,000)	$0
• Sales to CP&L (Revenues)	$33,279,000	$33,910,000	$36,486,000	$35,027,000	$38,142,000
• Average Monthly Power Purchases by Cities (MWh)	563,763	577,080	547,471	546,347	522,782
• Average Monthly Billings to Cities	$35,407,000	$35,245,000	$34,073,000	$34,539,000	$34,050,000

	1996	1995	1994	1993	1992
• Megawatt-hour Sales (MWh)	6,291,401	6,142,495	5,810,477	5,865,354	5,509,338
• Peak Billing Demand (kW)	1,116,786	1,194,209	1,135,450	1,155,200	1,112,185
• Operating Revenues	$460,674,000	$462,664,000	$458,023,000	$444,271,000	$398,585,000
• Excess of Revenues over Expenditures	$0	$0	$0	$20,830,000	$2,000
• Sales to CP&L (Revenues)	$38,416,000	$40,901,000	$61,302,000*	$53,609,000*	$39,987,000
• Average Monthly Power Purchases by Cities (MWh)	524,283	511,874	484,206	488,780	459,112
• Average Monthly Billings to Cities	$35,188,000	$35,147,000	$33,060,000	$32,555,000	$29,883,000

** The Harris sellback increased from 33 1/3% in 1992 to 50% in 1993 and 1994 as part of the Harris litigation settlement, then reduced to 33 1/3% until the sellback ends in 2007.*

ELECTRICITIES

North Carolina Municipal Power Agency Number 1
North Carolina Eastern Municipal Power Agency

1427 Meadowwood Boulevard ❑ Raleigh, North Carolina 27604
Post Office Box 29513 ❑ Raleigh, North Carolina 27626-0513
Telephone: 919/760-6000 ❑ Facsimile: 919/760-6050 ❑ Web Site: http://www.electricities.com