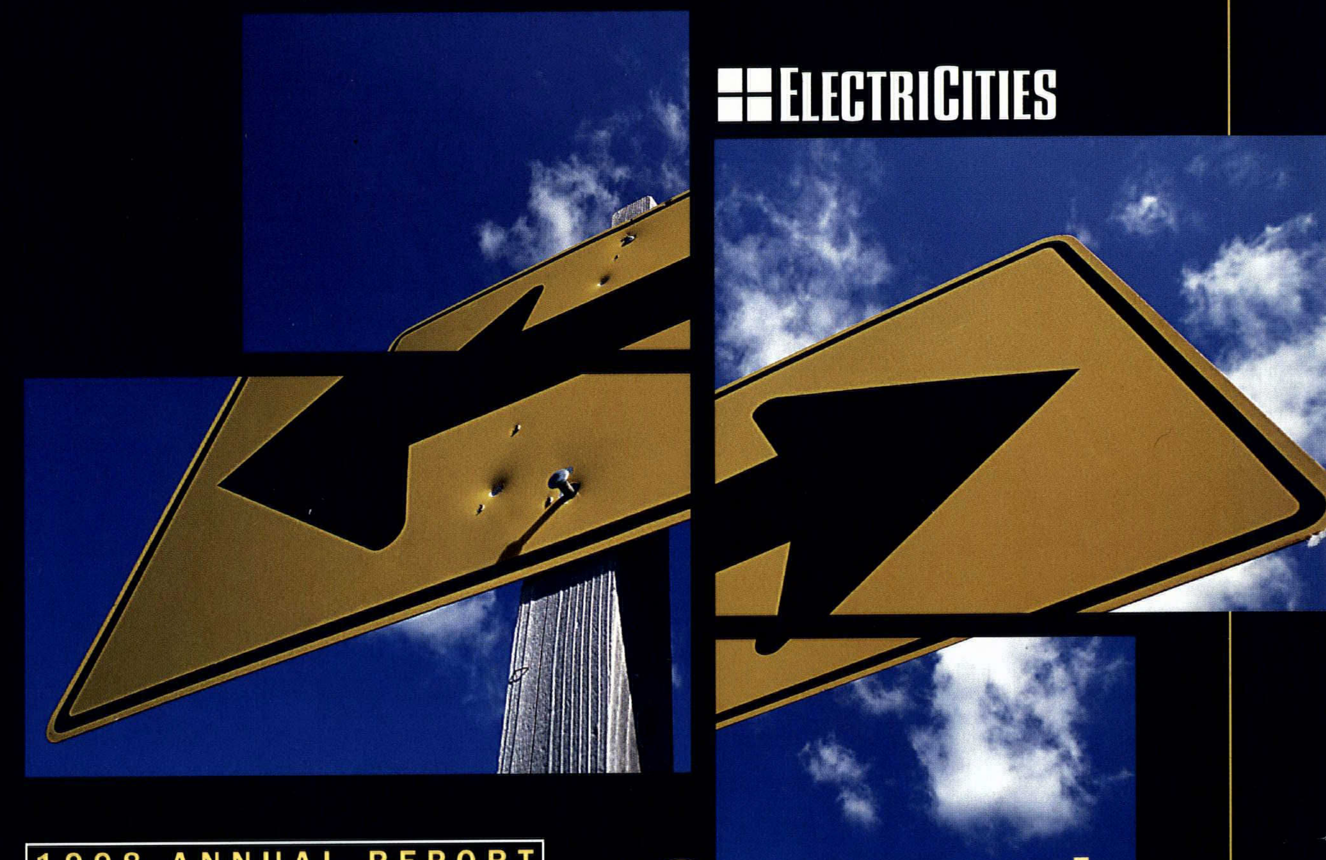
ELECTRICITIES

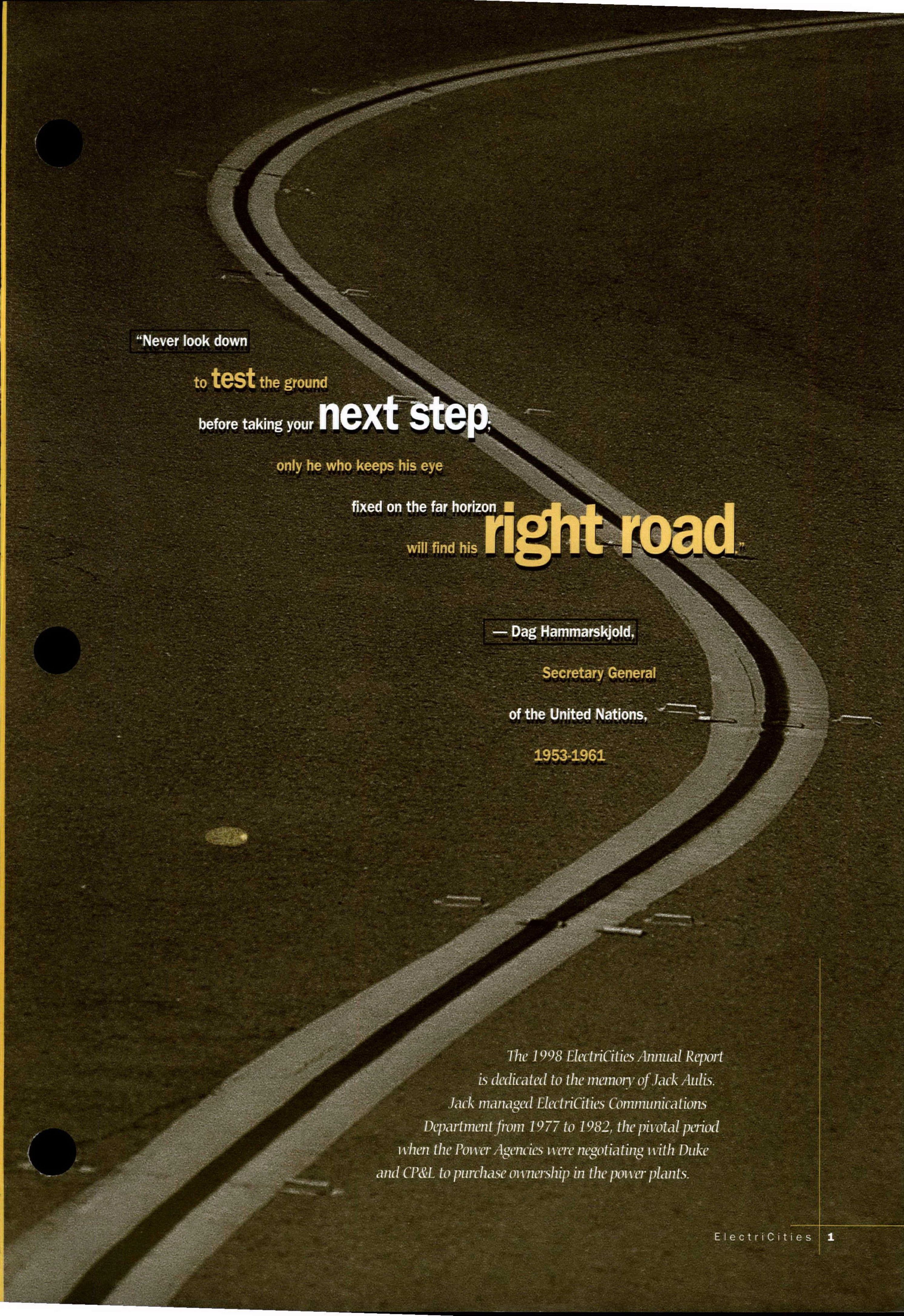


1998 ANNUAL REPORT

Public Power at a Crossroads

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 1

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY



"Never look down to **test** the ground before taking your **next step**; only he who keeps his eye fixed on the far horizon will find his **right road**."

— Dag Hammarskjold,
Secretary General
of the United Nations,
1953-1961

The 1998 ElectriCities Annual Report is dedicated to the memory of Jack Aulis. Jack managed ElectriCities Communications Department from 1977 to 1982, the pivotal period when the Power Agencies were negotiating with Duke and CP&L to purchase ownership in the power plants.

PUBLIC Power AT A CROSSROADS

AN INTRODUCTION

"As it is with groups of people, so it is with cities and towns.
When they associate themselves with others of like interests they can provide services
and reach goals far in excess of those to which they could reasonably aspire *singly and alone..."*
Excerpted from the Prologue to
75 Years of Service, A History of the North Carolina League of Municipalities
written in 1983 by Jack Aulis.

Over the span of more than 100 years, public power systems have served to illuminate cities and brighten the lives of North Carolinians across the state. Statesville was the first. More than 70 municipalities followed. When town officials pulled the switch that February night in 1889 they only wanted a better alternative to gas street lamps. They had no idea that their action set in motion the future of public power in North Carolina.

As more and more cities realized the early benefits of public power, many North Carolina towns began producing electricity before the private companies saw it as a profit-making business. More than public revenue, the sale of municipally owned electricity gave citizens control of their power supply. Local electric decisions were made by neighbors, friends, local merchants.

The concept of local unity was strengthened in 1965 when most of North Carolina's electric cities joined together to form what is now ElectriCities, a service organization for its members. Local control, local public service has remained a hallmark of municipal electric systems.

Today, public power in North Carolina is at a crossroads.

Thirty years ago, the energy crisis of the 1970s and 80s transformed the electric utility industry. Dramatic economic and regulatory changes are once again sweeping across the industry. Today as we look to the future, North Carolina's Municipal Power Agencies stand at the threshold of another dynamic transformation.

The road sign ahead reads competition. As it approaches, there are decisions to be made. Let us be mindful of Hammarskjold's advice and look to the far horizon, so we are sure to find the right road.

WHAT'S Inside
TABLE OF CONTENTS

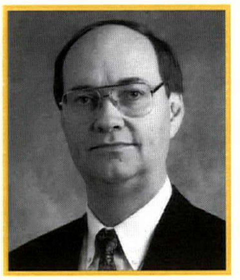
The audit reports of and financial information regarding each North Carolina Municipal Power Agency are included in this report. Each Power Agency is a separate and distinct legal entity and the inclusion of such information regarding both entities should not be construed to indicate any relationship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

MOVING PUBLIC POWER Forward:
PERSISTANCE IS THE KEY
A LETTER FROM THE CHAIRMAN AND CEO

"Nothing in the world can take the place of persistence."

These words from Calvin Coolidge set the tone for ElectriCities, NCMPA1 and NCEMPA in 1998. In fact, since the state began its debate on electric industry deregulation, ElectriCities has been persistent in making sure state leaders understand how crucial this issue is for our member cities.

William H. Batchelor
Chairman, Board of Directors



Jesse C. Tilton, III
Chief Executive Officer

Our aggressive grassroots lobbying campaign last year successfully brought forth the two most critical issues - high rates and stranded costs. There is no doubt that these issues must be addressed before a deregulation plan will take shape.

So as we now stand at a crossroads on this issue, we must continue to urge state leaders to move forward. We must remember Coolidge's remarks and, in particular, all of our efforts in 1998 that brought us to this point.

The year began on a dramatic note when ElectriCities presented the history of the Power Agencies and the reasons for the high debt and rates to the Study Commission on the Future of Electric Service. The presentation opened the eyes of many stakeholders to the dilemma we face and, in particular, that the cities did not enter into this decision alone.

The Study Commission's eight public hearings in March and April brought forth many strong arguments for ElectriCities' position on uniform recovery of stranded costs. But the end of the public hearings in April marked the end of Study Commission meetings, as the legislative short session dragged well past the summer.

Despite the slow-down in Study Commission activity, ElectriCities' lobbying efforts intensified as we brought our member cities more intimately into the process. Two June Mayors' meetings began the call to action. And in July, the Research Triangle Institute's report on electric rates only proved what ElectriCities had known all along - that there is a rate disparity between the Power Agency cities and those of Duke and CP&L. This report, and a need to urge the Study Commission to move forward with its plans, meant we had to make a move.

In late July, the Mayors' Day in Raleigh made a strong statement to lawmakers that this rate disparity issue must be addressed, or their demise would have a domino effect on the rest of the state. On this day, more than 100 mayors and city officials from the Power Agency cities came to Raleigh and held breakfast meetings all over the city with legislators. After breakfast, they went to the Legislature and talked to more lawmakers.

Despite all of our hard lobbying, the Study Commission did not meet again until November - a full seven months after its last meeting. It became apparent at that meeting that the Commission would not make a recommendation on deregulation in the 1999 session.

But all of our hard work paid off in one respect - the momentum and urgency to solve the state's rate disparity problem was beginning to become the real issue in the debate. This became evident when State Treasurer Harlan Boyles released his position on deregulation and the Power Agencies' debt in late December. His call for action to resolve the rate disparity issue, along with his own proposals for solving the stranded cost problem, breathed new life into a debate that had stalled with no progress in sight.

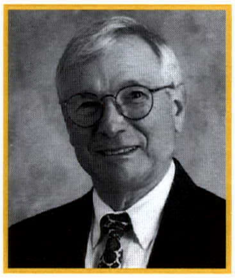
There is no doubt that 1998 was one of the most important years in the history of this organization. And we are very proud of the hard work and persistence the membership and our staff have thrown into this debate. We have established North Carolina "electric cities" as a major player in this issue, and we have successfully brought the cities' issues to the forefront, enough so that any deregulation plan cannot ignore the real issues - the state's rate disparity and stranded cost problems.

Persistence pays off. ElectriCities and its members proved that in 1998.

ELECTRICITIES Leadership

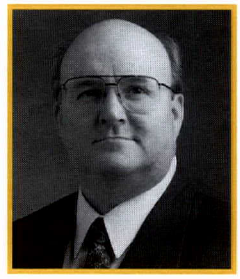
1998 BOARD OF DIRECTORS

William H. Batchelor
Chairman, Rocky Mount

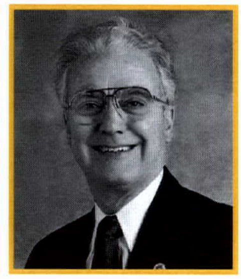


Smith D. Lingerfelt
Vice Chairman, Shelby

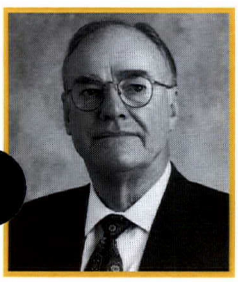
Samuel W. Noble, Jr.
Secretary, Tarboro



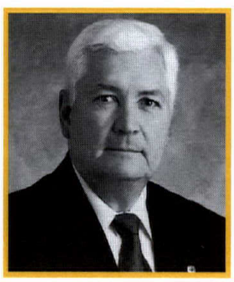
Steven K. Blanchard
Fayetteville



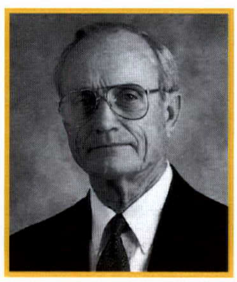
Cyrus L. Brooks
High Point



Franz F. Holscher
Gastonia

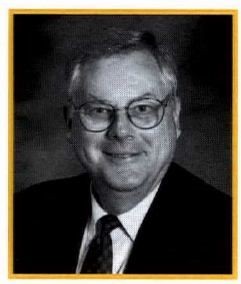


Jack F. Neel
Albemarle

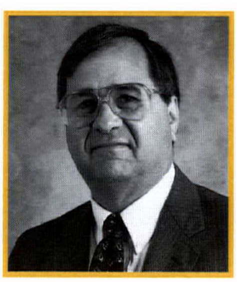


Winton R. Poole
Cornelius

Stephen H. Slough
Concord

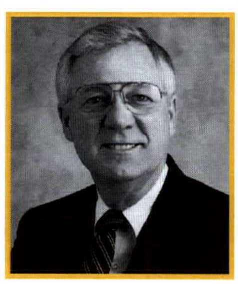


William M. Sutton
Apex

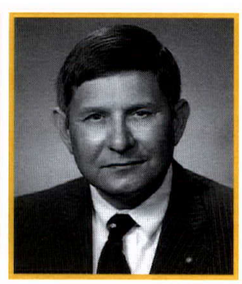


John T. Walser, Jr.
Lexington

Carey B. Washburn
Kinston



Claude R. Wilson
Robersonville



Ed A. Wyatt
Wilson

ELECTRICITIES MANAGEMENT

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

ElectriCities MEMBERSHIP

ALPHABETICAL LISTING OF MEMBER CITIES AND TOWNS IN 1998

City/Town	Year Electric System Established	Customers
Albemarle	1910	11,170
Apex	1917	5,568
Ayden	1916	3,509
Bamberg, SC	1905	1,784
Bedford, VA	1911	6,545
Belhaven	1920	1,221
Bennettsville, SC	1903	4,860
Benson	1913	1,779
Black Creek	Unavailable	751
Blackstone, VA	1888	2,000
Bostic	1920	181
Camden, SC	1902	13,000
Cherryville	1906	2,481
Clayton	1913	3,480
Concord	1901	18,333
Cornelius	1916	1,815
Culpeper, VA	1934	2,484
Dallas	1925	2,634
Danville, VA	1886	46,900
Drexel	1926	1,201
Edenton	1908	3,828
Elizabeth City	1926	10,400
Elizabeth City State University	1891	University
Elkton, VA	1924	1,151
Enfield	Prior to 1940	1,538
Farmville	1904	2,844
Fayetteville	Chartered 1905	64,407
Forest City	Early 1900s	4,357
Fountain	1903	358
Franklin, VA	1892	4,963
Fremont	1918	936
Gaffney, SC	1907	6,696
Gastonia	1919	25,423
Granite Falls	1923	2,162
Greenville	1905	47,787
Hamilton	1922	255
Harrisonburg, VA	1957	14,846
Hertford	1915	1,275
High Point	1893	33,455
Highlands	Unavailable	2,348
Hobgood	1922	349
Hookerton	1907	390
Huntersville	1916	1,836
Kings Mountain	1935	4,126
Kinston	1897	17,111
La Grange	1917	1,478

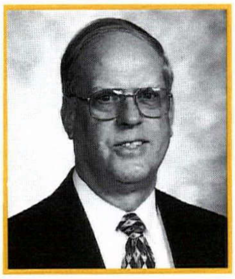
ELECTRICITIES

Membership

ALPHABETICAL LISTING OF MEMBER CITIES AND TOWNS IN 1998

City/Town	Year Electric System Established	Customers
Landis	1919	2,629
Laurens, SC	1922	5,168
Laurinburg	1925	5,494
Lexington	1904	17,575
Lincolnton	1900	2,760
Louisburg	1906	1,919
Lucama	1889	1,100
Lumberton	1915	8,750
Macclesfield	Unavailable	309
Maiden	1920	1,014
Manassas, VA	1912	13,826
Martinsville, VA	1900	8,173
Monroe	1900	8,646
Morganton	1916	7,786
Murphy	1953	3,700
New Bern	1901	15,663
New River Light & Power (Boone)	1915	6,646
Newton	1896	3,917
Pikeville	1918	545
Pinetops	Unavailable	715
Pineville	1939	2,162
Red Springs	1910	1,890
Richlands, VA	1922	3,000
Robersonville	1919	1,154
Rock Hill, SC	1911	23,964
Rocky Mount	1902	27,462
Scotland Neck	1903	1,693
Selma	1913	2,552
Sharpsburg	1920	1,388
Shelby	1912	7,711
Smithfield	1912	4,459
Southport	1916	1,904
Stantonsburg	1920	1,042
Statesville	1889	12,196
Tarboro	1897	5,816
UNC-Chapel Hill	1895	University and 430 campus retail customers
Wakefield, VA	1920	588
Wake Forest	1909	4,380
Walstonburg	1922	132
Washington	1903	12,046
Waynesville	1923	2,830
Western Carolina University	1920	1,890
Wilson	1892	29,423
Windsor	1920	1,718
Winterville	1900	1,400

North Carolina MUNICIPAL
POWER AGENCY NUMBER 1



Morris Baker
Chairman, NCMPA1

I can vividly recall the feelings of emotion and anxiety during those fearful days in the history of public power, the 1970s energy crisis. As wholesale customers of Duke Energy, we endured rate increase upon rate increase, and frantic forecasts of limited or no supply. It was that uncertainty, and lack of local control that lead 19 cities to band together as North Carolina Municipal Power Agency Number 1.

Today, we face another critical period in our history as the General Assembly deliberates restructuring of the $7 billion electric industry in our state. The stakes are high. For NCMPA1 and participants, we will be challenged to our very core with this issue. But in the prophetic words of Margaret Meade, "Never doubt that a small group of committed citizens can change the world. Indeed, it's the only thing that has." Our small group can make an impact!

There were many noteworthy accomplishments for NCMPA1 and its participants this past year. Financially, a refunding issue achieved $6.8 million in present value savings in debt service without increasing the amount of debt or extending its maturity. As well, it provided for the lowest interest costs issued in the history of NCMPA1!

Operations-side successes include continued attention and dedication to customer retention programs and pricing options. Full installation of "smart meters" gives participants cutting edge tools to offer load research and profit analysis to assist customers in the most efficient management of energy costs. Load growth in energy sales was up 6.8 percent in 1998, while at the same time load management efforts resulted in savings of more than $8.4 million for NCMPA1, its participants and their customers.

Significant efforts by the Power Agency resulted in a stepped up pace on Y2K compliance activities, as well as progress on studying a Customer Information System (CIS) effort for NCMPA1 and participant cities. Also in the area of maximizing efficiencies, consolidated management services opportunities proved successful in 1998, with the Huntersville/Cornelius system realizing 10 percent operational savings as the customer base grew by 11 percent.

Another significant achievement was in the area of surplus energy sales. Since the program began in 1996, surplus energy sales have generated more than $18.7 million in revenue and $6.4 million in profit for the Power Agency. Profit estimates from surplus sales for 1999 reach $4 million, with projections of $8 million for the year 2000 as a result of increased retained capacity.

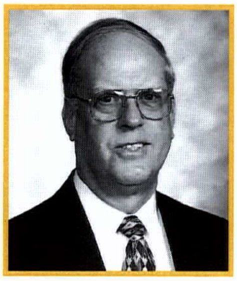
Indirect efforts of Duke Energy in 1998 may also provide future benefits to NCMPA1. As part of a consortium of companies, Duke this fall submitted a proposal to the Department of Energy to re-use government stock-piled plutonium to generate electricity at the Catawba and McGuire Nuclear Stations. As we go to press, the DOE has awarded Duke Energy and its consortium the contract to use mixed-oxide, or "MOX," fuel beginning in the year 2007. Catawba owners should realize fuel cost savings for the period 2007-2022, as compared to the market price of uranium fuel. Additionally, Duke has filed a request with the Nuclear Regulatory Commission to extend the operating licenses for the three units at the Oconee Nuclear Station. A favorable ruling on the Oconee request would have positive implications for a similar filing for Catawba, one which may help to increase the plant's market value. We will continue to watch these developments.

This year has been a busy and challenging one. As we move quickly toward the next century, the road ahead will be no less formidable. But we, as public power – that small group of committed citizens, have the determination to forge ahead, to create opportunities which will provide a better community for those we serve.

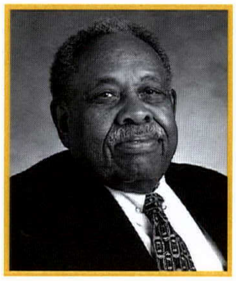
I have enjoyed my year of service as your Chairman, and wish our new Chairman – Lexington Mayor Richard Thomas – much success as he assumes his duties.

NCMPA1 Board OF COMMISSIONERS

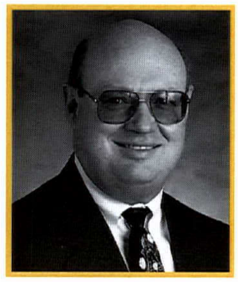
AS OF DECEMBER 31, 1998



Morris A. Baker
Chairman
Town Manager, Drexel



Arthur E. Peterson
Vice Chairman
Statesville



Lloyd D. Shank, Jr.
Secretary-Treasurer
Dir. of Electric Util., High Point

1998 OFFICERS

COMMISSIONERS

- **Mr. Raymond I. Allen**
  City Manager
  Albemarle
- **Mr. Ray G. Bailey**
  Council Member
  Bostic
- **Ms. Janice L. Hovis**
  City Manager
  Cherryville
- **Mr. Winton R. Poole**
  Town Commissioner
  Cornelius
- **Mr. Morris A. Baker**
  Town Manager
  Drexel
- **Mr. Franz F. Holscher**
  Council Member
  Gastonia
- **Ms. Linda K. Story**
  Town Manager
  Granite Falls
- **Ms. Rebecca R. Smothers**
  Mayor
  High Point
- **Mr. Ed Humphries**
  Town Manager
  Huntersville
- **Mr. Tommy Branch**
  Dir. of Public Works
  Landis
- **Mr. Richard L. Thomas**
  Mayor
  Lexington
- **Mr. Stephen H. Peeler**
  Dir. of Public Works & Utilities
  Lincolnton
- **Mr. Kevin C. Sanders**
  Administrative Assistant
  Maiden
- **Mr. Jerry E. Cox**
  City Manager
  Monroe
- **Mr. Dan Brown**
  Dir. of Electric Services
  Morganton
- **Mr. Edward F. Burchins**
  City Manager
  Newton
- **Vacant**
  Pineville
- **Mr. Pete Gilbert**
  Council Member
  Shelby
- **Mr. Arthur E. Peterson**
  Council Member
  Statesville

ALTERNATE COMMISSIONERS

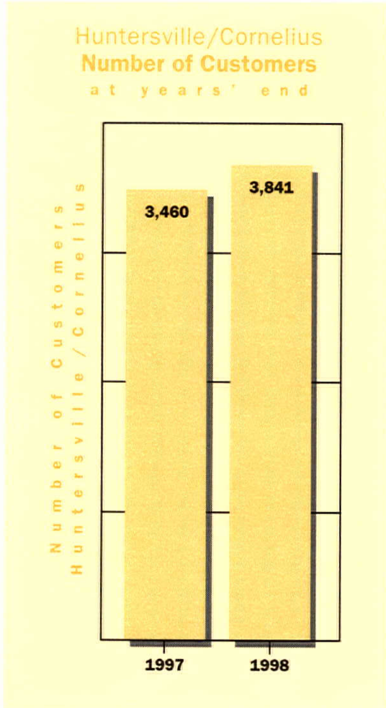
- **Mr. Tidus Stanback**
  Albemarle
- **Mr. Jack F. Neel**
  Council Member
  Albemarle
- **Mr. James Morrow**
  Council Member
  Bostic
- **Mr. Jack D. Davis**
  Mayor
  Cherryville
- **Mr. Thurman Ross Jr.**
  Town Commissioner
  Cornelius
- **Mr. Benny J. Orders**
  Alderman
  Drexel
- **Mr. Bob Wilkerson**
  Council Member
  Gastonia
- **Mr. Barry Hayes**
  Mayor
  Granite Falls
- **Dr. Caryl B. Burns**
  Council Member
  Granite Falls
- **Mr. Stribling P. Boynton**
  City Manager
  High Point
- **Mr. Lloyd D. Shank, Jr.**
  Dir. of Electric Utilities
  High Point
- **Mr. Charles Guignard**
  Town Commissioner
  Huntersville
- **Vacant**
  Landis
- **Mr. C. Phillip Head Sr.**
  Council Member
  Lexington
- **Mr. L. Klynt Ripple**
  Utilities Commission Member
  Lexington
- **Mr. Jeff B. Emory**
  City Manager
  Lincolnton
- **Mr. Bobby G. Huitt**
  Mayor
  Lincolnton
- **Mr. Kent M. Auton**
  Council Member
  Maiden
- **Mr. Donald D. Mitchell**
  Director of Electric Utilities
  Monroe
- **Mr. Robert J. Smith**
  Council Member
  Monroe
- **Mr. Dale Herron**
  Electric Superintendent
  Morganton
- **Mr. Jay C. Stowe**
  Dir. of Public Utilities
  Newton
- **Ms. Mary Ann Creech**
  Town Administrator
  Pineville
- **Mr. Smith D. Lingerfelt**
  Energy Services Manager
  Shelby
- **Mr. Herbert "Jim" Lawton**
  Council Member
  Statesville
- **Mr. Larry M. Cranford**
  Electric Utility Director
  Statesville

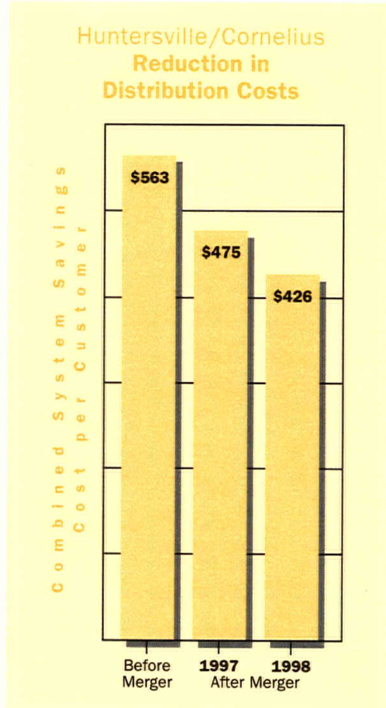
Participants ELECTRIC SYSTEMS

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 1

City/Town	Established	Customers	Revenues	% Ownership
Albemarle	1910	11,170	*1998* - $22,027,885 *1997* - $20,508,131	7.6043
Bostic	1920	181	*1998* - $210,528 *1997* - $207,957	0.0869
Cherryville	1906	2,481	*1998* - $4,947,417 *1997* - $4,639,205	1.5788
Cornelius	1916	1,815	*1998* - $2,725,179 *1997* - $2,200,886	0.3621
Drexel	1926	1,201	*1998* - $1,571,250 *1997* - $1,450,719	0.5070
Gastonia	1919	25,423	*1998* - $52,254,195 *1997* - $49,161,775	17.1205
Granite Falls	1923	2,162	*1998* - $4,112,153 *1997* - $3,993,978	0.9125
High Point	1893	33,455	*1998* - $72,057,894 *1997* - $67,571,252	18.9600
Huntersville	1916	1,836	*1998* - $3,088,890 *1997* - $2,627,369	0.6228
Landis	1919	2,629	*1998* - $3,258,121 *1997* - $2,992,068	1.1298
Lexington	1904	17,575	*1998* - $40,426,151 *1997* - $37,850,544	12.9345
Lincolnton	1900	2,760	*1998* - $5,152,973 *1997* - $4,878,517	1.6078
Maiden	1920	1,014	*1998* - $4,534,877 *1997* - $4,810,735	1.2891
Monroe	1900	8,646	*1998* - $32,750,818 *1997* - $30,864,928	10.0377
Morganton	1916	7,786	*1998* - $21,734,626 *1997* - $20,551,686	6.7352
Newton	1896	3,917	*1998* - $7,026,162 *1997* - $6,624,447	2.1147
Pineville	1939	2,162	*1998* - $7,398,380 *1997* - $6,941,845	0.5359
Shelby	1912	7,711	*1998* - $13,839,029 *1997* - $12,910,085	5.9965
Statesville	1889	12,196	*1998* - $28,875,393 *1997* - $27,321,842	9.8639

Overall, NCMPA1 had a productive year that was punctuated by cost efficient plant operations and increased revenues in energy sales. Surplus sales, in particular, far exceeded projections during 1998. Above and beyond business as usual, the Agency also dedicated time and resources toward helping its member cities prepare for the year 2000.





PLANT INFORMATION

	Capacity* Factor %	Availability* Factor %
• Catawba Unit 1	90.0	90.5
• Catawba Unit 2	87.7	86.5
• McGuire Unit 1	91.5	90.1
• McGuire Unit 2	103.0	99.5

** These numbers are reported by Duke to the Nuclear Regulatory Commission in the units' December 1998 Operating Data Report.*

McGuire Unit 1 had a refueling outage on May 29 which ended on July 1. This 33.8-day refueling outage was the shortest ever at a Duke Energy Nuclear Station, breaking the record of 37.7 days previously established on Catawba Unit 1.

The McGuire Station had a 1998 capacity factor of 97.3 percent, the best year ever for a Duke Nuclear Station. The Station's 1.23-cents per kilowatt-hour cost for fuel and operation and maintenance should place the McGuire Station as one of the 10 lowest-cost nuclear stations in the country for 1998.

The Catawba Station had a 1998 capacity factor of 88.9 percent, its second best year ever. The Station's 1.35 cents per kilowatt-hour should put Catawba in the top 25 percent lowest-cost nuclear stations in the country.

All four units were among the top 50 generating plants in the world in 1998. This rating is based on actual gross generation within a one-year period.

HUNTERSVILLE/CORNELIUS

The consolidated electric operations for Huntersville/Cornelius illustrates how two systems, operating together, can be a cost efficient measure for NCMPA1. By dedicating staff solely to electric service and sharing equipment costs, Huntersville/Cornelius has served as an example of how to maximize resources. This organizational structure produced a savings of 10 percent for these two towns in 1998, while increasing the customer base by more than 11 percent. Since the merger, a 24 percent cost savings has been realized, and the number of customers has increased more than 35 percent.

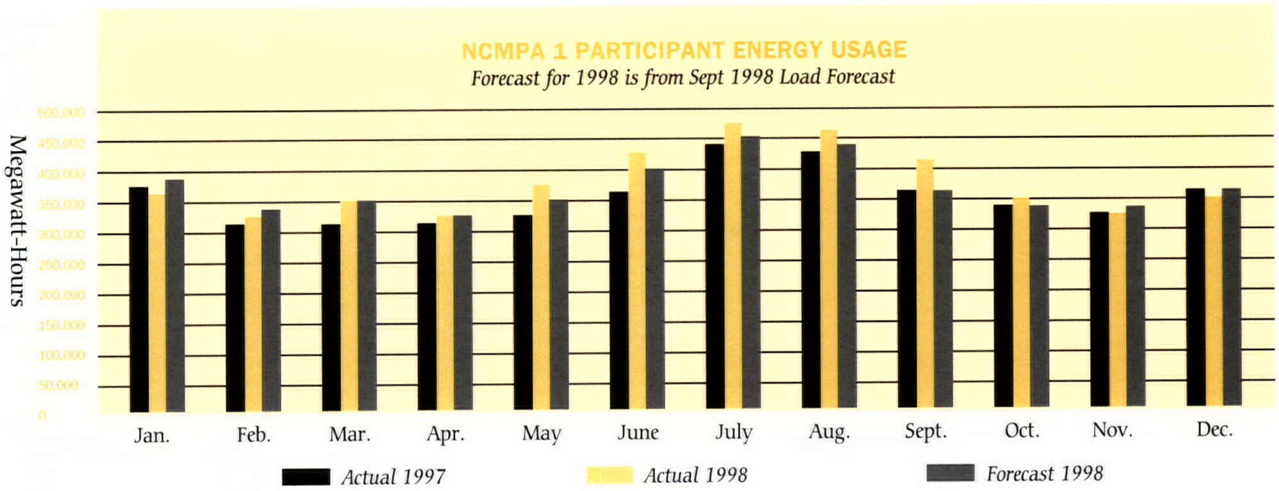
ECONOMIC DEVELOPMENT

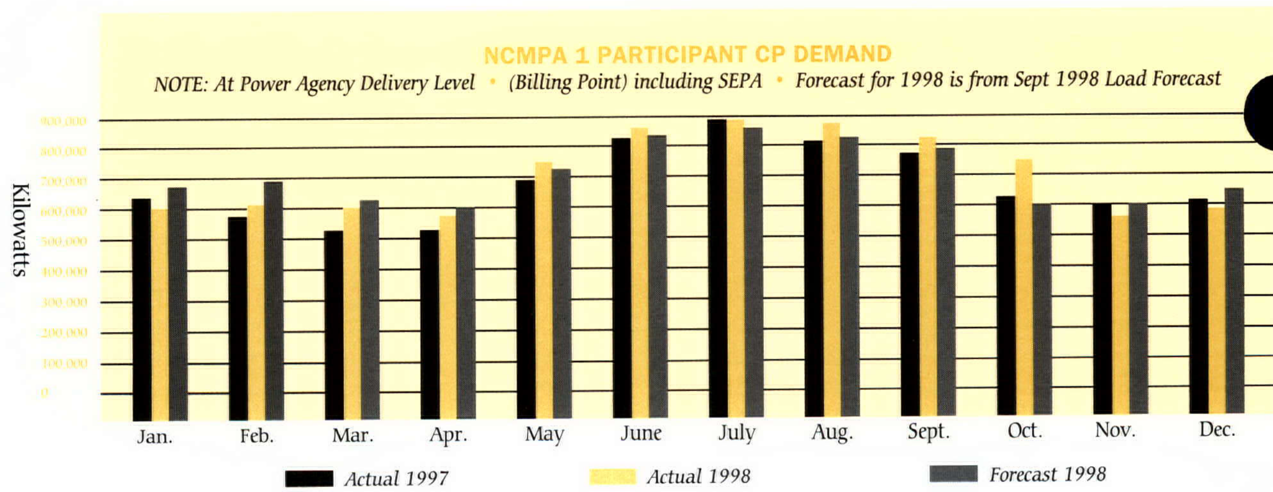
Expanding load growth is another initiative NCMPA1 has used to drive the cost of power down for its customers. During the past year the Agency provided economic development rates as an incentive to

CONTINUED

Operational HIGHLIGHTS

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 1





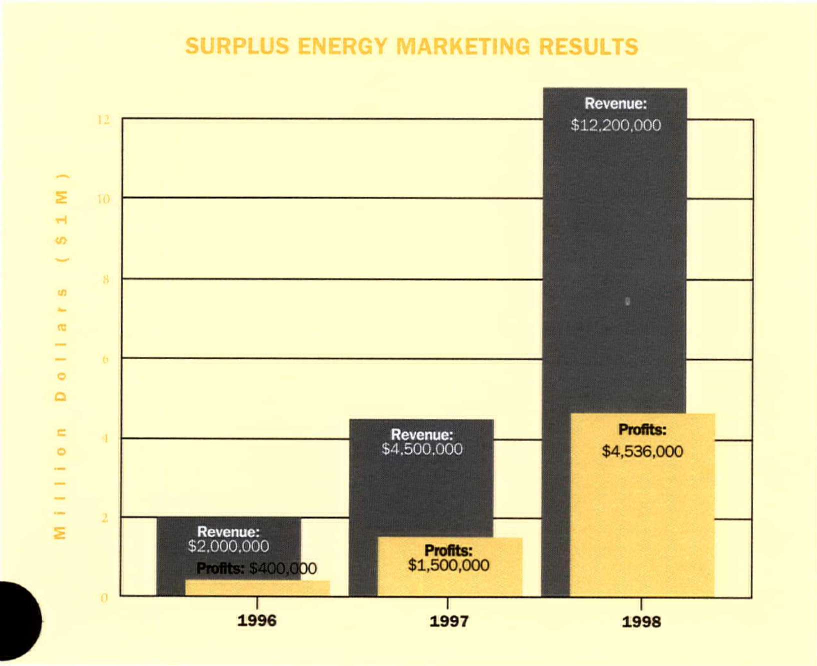
more than 35 industrial and commercial customers for new sites that helped to increase NCMPA1's total load. It is anticipated that these efforts will bring 2,132 new jobs, $77.1 million in investments and 13.9 MW of new load to the Agency's cities over the next few years.

Similarly, the Agency's load management program resulted in more than $8.4 million in savings. This operational strategy enables NCMPA1 to reduce its cost of operation during the coincident peak.

In an effort to expand the scope of "value-added services," pilot programs were set up in High Point, Lexington and Monroe to gauge customers' response to new offerings. Offerings were also tested in Fayetteville, Kinston, Tarboro and Washington. The success of these pilots have provided the impetus for establishing a strategy to offer new energy services to customers. NCMPA1 will partner with Honeywell Inc. in 1999 to provide these programs in its member cities.

ENERGY AND DEMAND

Energy sales to NCMPA1 participants totaled 4,496,603 MWh. A warm summer resulted in 6 percent higher total energy sales to participants for the year, compared to 1997.



SURPLUS SALES

A relatively new program is NCMPA1's surplus energy sales. This year NCMPA1 generated $12.2 million in revenue and $4.5 million in profit through this effort. It is estimated that this program will generate more than $4 million in profit in 1999. Due to an increase in retained capacity, it is projected that profits on surplus sales will climb to $8 million in 2000. NCMPA1 reached a total of 18 surplus energy customers in 1998 - some as far away as Illinois, Florida and Texas.

MOX FUEL

Another new venture for NCMPA1 this year was the MOX fuel proposal. As we went to press the Department of Energy chose Duke and its consortium to use MOX fuel at its plants. This agreement enables all owners of the Catawba Nuclear Station, including NCMPA1, to help with the elimination of surplus plutonium, and reduce Catawba's fuel cost over a 15-year period beginning in 2007.

YEAR 2000

Preparation for the Year 2000 was a primary function of NCMPA1 staff in 1998. The Agency anticipates completing all remediation of its internal systems by the end of the first quarter in 1999. NCMPA1 staff have worked to increase general awareness about this issue and support its member cities in their Y2K preparation efforts this year. In addition, NCMPA1 is monitoring the progress of Duke Energy as the Year 2000 approaches, and keeping the cities informed about its progress toward Y2K readiness.

During 1998, ElectriCities launched a pilot project in New Bern to examine how the turnover to the year 2000 may affect the delivery of electric service. The project generated positive results, finding only 15 items that were non-compliant out of an inventory of 372 micro-processor items. None of these items are integral to the electrical distribution systems, and all 15 items needing repair or replacement to be Y2K ready were located in personal computers' software or hardware. A second pilot project was started in February 1999 in Lexington.

A series of educational summits was offered by NCMPA1 and ElectriCities to assess the progress of member cities' Y2K preparations and offer support of their efforts. The summits were well-attended, and indicated that the majority of the cities were well on their way toward Y2K readiness. NCMPA1 will continue to assist and support the cities with their year 2000 efforts to ensure readiness by Summer 1999.

A formal Year 2000 Readiness Plan was adopted by ElectriCities' Board of Directors. The plan was designed to coincide with the schedule outlined by the North American Electric Reliability Council (NERC). NCMPA1 and ElectriCities have entered the final stages of this process, and have participated in discussions on contingency planning with the Southeastern Reliability Council as it works to complete its Y2K preparation.

INVESTMENT PORTFOLIO STATISTICS

Earnings

*Earnings**	*Income*	*Rate of Return*
1998	$58,920,000	6.79%
1997	$56,967,000	6.66%

Market Value as of 12/31*

	Value	*Average Maturity*
1998	$999,701,000	5.0 years
1997	$956,035,000	5.2 years

Transactions

	Number	*Amount*
1998	731	$9,557,375,000
1997	734	$9,870,423,000

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

DEBT STATISTICS

Debt Outstanding 12/31

	Balance (Thousands)	*Weighted Average Interest Cost*
Fixed Rate Bonds		
1998	$2,185,387	6.04%
1997	$2,225,402	6.16%
Tax-Exempt Commercial Paper		
1998	$200,600	3.75%
1997	$200,600	4.43%

NCMPA 1 BOND RECONCILIATION

Bonds Outstanding 12/31/97		$2,225,402,000
Issued Series 1998A	+	128,925,000
		2,354,327,000
Matured 1/1/98	-	40,015,000
Refunded	-	128,925,000
Bonds Outstanding 12/31/98		$2,185,387,000

NCMPA 1 BONDS OUTSTANDING

Series 1985B	$ 80,575,000
Series 1988	11,052,000
Series 1990	113,285,000
Series 1992	1,123,285,000
Series 1993	543,035,000
Series 1995A	79,440,000
Series 1997A	105,790,000
Series 1998A	128,925,000

INDEPENDENT Auditors' REPORT

NORTH CAROLINA MUNICIPAL POWER AGENCY NUMBER 1
BOARD OF DIRECTORS

We have audited the accompanying balance sheets of North Carolina Municipal Power Agency Number 1 as of December 31, 1998 and 1997 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 generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North Carolina Municipal Power Agency Number 1 at December 31, 1998 and 1997, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

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 Schedule of Revenues and Expenses per Bond Resolution and Other Agreements and Schedule 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.

The year 2000 supplementary information on page 33 is not a required part of the general purpose financial statements, but is supplementary information required by the *Governmental Accounting Standards Board*, and we did not audit and do not express an opinion on such information. Further, we were unable to apply to the information certain procedures prescribed by professional standards because of the nature of the subject matter underlying the disclosure requirements and because sufficiently specific criteria regarding the matters to be disclosed have not been established. In addition, we do not provide assurance that North Carolina Municipal Power Agency Number 1 is or will become year 2000 compliant, that North Carolina Municipal Power Agency Number 1's year 2000 remediation efforts will be successful in whole or in part, or that parties with which North Carolina Municipal Power Agency Number 1 does business are or will become year 2000 compliant.

KPMG LLP

RALEIGH, NORTH CAROLINA • APRIL 16, 1999

Balance SHEETS

($000s)

ASSETS	December 31, 1998	1997
• Electric Utility Plant		
Electric plant in service, net of accumulated depreciation of $471,264 and $429,935	$ 974,799	$ 997,544
Construction work in progress	3,944	22,195
Nuclear fuel, net of accumulated amortization of $58,453 and $40,494	48,456	46,621
	1,027,199	1,066,360
• Non-Utility Property and Equipment, net	2,215	2,305
• Special Funds Invested (Notes C and E):		
Bond fund	295,899	284,354
Reserve and contingency fund	18,581	18,971
Special reserve fund	1,086	1,043
	315,566	304,3[illegible]
• Trust for Decommissioning Costs	102,203	86,2[illegible]
• Operating Assets:		
Funds invested (Notes C and E):		
Revenue fund	348,293	374,492
Operating fund	120,720	106,945
Supplemental fund	120,561	91,933
	589,574	573,370
Participant accounts receivable	19,173	19,199
Operating accounts receivable	2,352	2,697
Prepaid expenses	37,700	36,972
	648,799	632,238
• Deferred Costs:		
Unamortized debt issuance costs	36,563	37,997
Costs of advance refundings of debt	318,157	315,261
	$2,450,702	$2,444,774

SEE NOTES TO FINANCIAL STATEMENTS.

BALANCE Sheets

($000s)

LIABILITIES AND RETAINED EARNINGS	December 31, 1998	1997
• Long-Term Debt:		
Bonds, net of unamortized discount (Note E)	$2,011,862	$2,038,572
• Special Funds Liabilities:		
Current maturities of bonds (Note E)	50,560	40,015
Accrued interest on bonds	58,836	59,012
Tax-exempt commercial paper (Note F)	200,600	200,600
Accrued interest on commercial paper	652	915
	310,648	300,542
• Liability for Decommissioning Costs	79,435	68,811
• Operating Liabilities:		
Accounts payable	777	601
Accrued taxes	13,770	13,704
	14,547	14,305
• Deferred Revenues, net (Note D)	26,810	15,144
• Commitments and Contingencies (Notes F and G)		
• Retained Earnings	7,400	7,400
	$2,450,702	$2,444,774

SEE NOTES TO FINANCIAL STATEMENTS.

SCHEDULE OF Revenues AND EXPENSES

AND CHANGES IN RETAINED EARNINGS ($000s)

	Year Ended December 31, 1998	1997
Operating Revenues:		
Sales of electricity to participants	$257,268	$246,167
Sales of electricity to utilities	102,551	119,698
Other revenues (Note H)	1,312	1,265
	361,131	367,130
Operating Expenses:		
Operation and maintenance	73,830	80,818
Nuclear fuel	24,040	25,301
Interconnection services:		
Purchased power	49,191	47,170
Transmission and distribution	12,980	12,934
Other	192	134
	62,363	60,238
Administrative and general	25,836	35,1[illegible]
Gross receipts and excise taxes	10,788	10,285
Property tax	12,866	12,965
Depreciation	47,892	45,269
	257,615	270,063
Net Operating Income	103,516	97,067
Interest Charges (Credits):		
Interest expense	126,466	131,263
Amortization of debt refunding costs	23,106	21,842
Amortization of debt discount and issuance costs	6,904	7,037
Net increase in fair value of investments	(12,045)	(15,022)
Investment income	(52,581)	(52,255)
	91,850	92,865
(Deferred Revenues) (Note D)	(11,666)	(4,202)
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 NOTES TO FINANCIAL STATEMENTS.

STATEMENTS OF Cash FLOWS
($000s)

	Year Ended December 31, 1998	1997
Cash Flows from Operating Activities:		
Receipts from sales of electricity	$ 358,640	$ 368,164
Receipts from other revenues	1,312	1,265
Payments of operating expenses	(183,004)	(195,525)
Net cash provided by operating activities	176,948	173,904
Cash Flows from Capital and Related Financing Activities:		
Bonds issued	128,925	106,500
Bonds refunded	(128,925)	(110,940)
Interest paid	(124,941)	(133,253)
Refunding Trust Fund requirement	(5,783)	(4,808)
Additions to electric utility plant, and non-utility property and equipment	(31,086)	(44,036)
Bonds retired	(40,015)	(43,240)
Debt discount and issuance costs paid	(3,805)	(12,275)
Net cash used for capital and related financing activities	(205,630)	(242,052)
Cash Flows from Investing Activities:		
Sales and maturities of investment securities	9,358,517	9,860,050
Purchases of investment securities	(9,381,154)	(9,842,206)
Investment earnings receipts from non-construction funds	51,884	50,308
Net cash provided by investing activities	29,247	68,152
Net Increase in Operating Cash	565	4
Operating Cash, Beginning of year	6	2
Operating Cash, End of year	$ 571	$ 6

SEE NOTES TO FINANCIAL STATEMENTS.

STATEMENTS OF CASH Flows (CONT.)

($000s)

	Year Ended December 31, 1998	1997
• Reconciliation of Net Operating Income To Net Cash Provided by Operating Activities:		
Net Operating Income	$103,516	$ 97,067
Adjustments:		
Depreciation	47,891	45,269
Amortization of nuclear fuel	24,040	25,301
Changes in assets and liabilities:		
Decrease in participant accounts receivable	26	218
Decrease in operating accounts receivable	345	659
(Increase) decrease in prepaid expenses	(728)	3,756
Increase in accounts payable	1,792	1,200
Increase in accrued taxes	66	434
Total Adjustments	73,432	76,8[illegible]
Net Cash Provided by Operating Activities	$176,948	$173,90[illegible]

SEE NOTES TO FINANCIAL STATEMENTS.

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 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 agrees to sell back to Duke, on a take-or-pay basis, capacity from each Catawba unit in decreasing amounts. In calendar years 1998 and 1997, the Agency retained approximately 81 percent and 74 percent, respectively, of the Agency's share of the station's aggregate available capacity, and will retain increasing amounts hereafter through December 31, 2000. Thereafter, the Agency retains 100 percent of its share and the sell-back arrangement terminates.

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 the issuance of 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 from Duke. 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 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), 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.

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. These measures, together with increasing customer demand for lower-priced electricity and other energy services, have accelerated the industry's movement toward more competitive pricing structures. The Agency and its Board of Directors are addressing the Agency's position relative to deregulation. In addition, the Agency periodically reviews its regulatory assets and the impact of recovering such assets on Agency rates.

In April 1997, the North Carolina legislature created the "Study Commission on the Future of Electric Service in North Carolina" (Study Commission). The Study Commission is comprised of 23 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 to examine 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. The Study Commission was originally charged with issuing a final report of the results of its study and its recommendations to the General Assembly of North Carolina in early 1999. However, current projections are that the Study Commission report will not be presented until 2000.

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 generally accepted accounting principles (GAAP). The Agency has adopted the principles promulgated by the Governmental Accounting Standards Board (GASB) and Financial Accounting Standard (FAS) 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 regulated assets even in a market environment.

- ***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, 1998, the remaining composite average life for Catawba's assets was 22 years. Original costs of major classes of the Agency's electric plant in service at December 31, 1998 and 1997 are as follows (in thousands of dollars).

	December 31, 1998	December 31, 1997
Land	$ 19,768	$ 19,768
Structures and improvements	389,199	386,861
Reactor plant equipment	594,893	550,773
Turbo generator units	165,145	165,145
Accessory electric equipment	123,576	120,590
Miscellaneous plant equipment	48,731	47,658
Station equipment	10,959	10,959
Unclassified	93,792	125,725
	1,446,063	1,427,479
Accumulated depreciation	(471,264)	(429,935)
	$ 974,799	$ 997,544

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

- **Construction Work in Progress**

All expenditures related to capital additions, including interest expense net of investment income on funds not yet expended, are capitalized as construction work in progress until such time as they are completed and transferred to Electric Plant in Service. 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, including interest expense net of investment income on funds not yet expended, are capitalized until such time as the cores are placed in the reactor. At that time, 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 $6,326,000 and $6,034,000 for the years ended December 31, 1998 and 1997, 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 $820,000 and $805,000 in 1998 and 1997, 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. On June 8, 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 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, 1998 and 1997 are as follows (in thousands of dollars).

	December 31, 1998	1997
• Land	$ 710	$ 710
• Structures and improvements	1,499	1,499
• Computer equipment	1,035	1,253
• Telemetry equipment	422	259
	3,666	3,720
• Accumulated depreciation	(1,451)	(1,415)
	$2,215	$2,305

- ***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.

- ***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 the decommissioning cost figure of $105 million per unit (1986 dollars) set forth in the NRC regulations. 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.

Estimates of the future costs of decommissioning the units are based on the most recent site specific study which was conducted in 1994. The Agency's portion of decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, is $224,250,000 stated in 1994 dollars.

- ***Deferred Costs***

Unamortized debt issuance costs, shown net of accumulated amortization of $8,874,000 and $6,966,000 at December 31, 1998 and 1997, 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 $124,513,000 and $130,089,000 at December 31, 1998 and 1997, respectively, are deferred and amortized over the term of the debt issued on refunding. Deferred revenues/net costs to be recovered from future billings to participants are not amortized but will be recovered through future rates (See Note D).

- ***Discounts on Bonds***

Discounts (net of premiums) on bonds, shown net of accumulated amortization of $30,992,000 and $25,995,000 at December 31, 1998 and 1997 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.

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 Option 2, a single financial institution collateral pool. Under Option 2, 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 Option 2. Because of the inability to measure the exact amount of collateral pledged for the Agency under Option 2, the potential exists for under-collateralization. However, the State Treasurer enforces strict standards for each Option 2 depository, which minimizes any risk of under-collateralization. At December 31, 1998 and 1997 the Agency had $129,000 and $10,000, 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 invest-

• INVESTMENTS ($000s)

	December 31, 1998 Carrying Amount	1998 Market Value	1997 Carrying Amount	1997 Market Value
• Repurchase agreements	$206,146	$ 206,146	$ 196,405	$ 196,405
• U.S. government securities	56,487	58,247	88,084	88,755
• U.S. government agencies	358,353	372,013	350,339	359,422
• Municipal bonds	27,468	29,130	28,104	29,410
• Collateralized mortgage obligations	228,978	232,038	193,628	196,000
	877,432	897,574	856,560	869,992
• Decommissioning Trust securities	79,358	102,127	68,609	86,043
• Operating cash	571	571	6	6
• Restricted cash	2	2	4	4
• Accrued interest	7,069	7,069	7,938	7,938
• Total funds invested	$964,432	$1,007,343	$ 933,117	$ 963,983
Consisting of:				
• Special funds invested		$ 315,566		$ 304,368
• Decommissioning Trust		102,203		86,245
• Operating assets		589,574		573,370
		$1,007,343		$ 963,983

• DEFERRED REVENUES ($000s)

	Year Ended December 31, 1998	Year Ended December 31, 1997	Inception to December 31, 1998	Inception to December 31, 1997
GAAP Items Not Included in Billings to Participants:				
• Interest expense	$124,879	$ 129,621	$2,085,739	$1,960,860
• Depreciation and amortization	67,788	64,325	710,353	642,565
• Increase in fair value of investments	(12,045)	(15,022)	(42,911)	(30,866)
• Training costs			6,696	6,696
	180,622	178,924	2,759,877	2,579,255
Bond Resolution Requirements Included in Billings to Participants:				
• Special funds deposits	10,456	6,449	448,786	438,330
• Debt service	168,348	162,715	2,200,065	2,031,717
• Investment income not available for operating purposes	26,395	23,791	296,790	270,395
• Special funds excess valuations	(12,911)	(9,829)	(158,954)	(146,043)
	192,288	183,126	2,786,687	2,594,399
• (Deferred revenues) net costs to be recovered from future billings to participants	$ (11,666)	$ (4,202)	$ (26,810)	$ (15,144)

ments, except repurchase agreements, are considered Category 1. Repurchase agreements are considered Category 3. The Agency's investments are detailed in the table at the upper left (in thousands of dollars).

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

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

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. To the extent that funds collected for reserve accounts exceeds costs to be recovered, the Agency has net deferred revenues. 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 Financial Accounting Standard (FAS) No. 121, "Accounting for the Impairment of Long Lived Assets and for Assets to Be Disposed Of."

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, rates may be revised.

(Deferred revenues) net costs to be recovered from future billings to participants includes the following, detailed in the table at the lower left (in thousands of dollars).

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.

As of December 31, 1997, the Agency had outstanding $2,225,402,000 of bonds. On January 1, 1998, the Agency made principal payments of $40,015,000 for maturing bonds. In April 1998, an additional $128,925,000 of bonds were issued (Series 1998A). Proceeds of the Series 1998A bonds were used to establish a trust for advance refunding $45,040,000 of the Series 1985B bonds and to refund $35,000,000 and $48,885,000 of the Series 1988 bonds and Series 1992 bonds, respectively, bringing the total outstanding bonds at December 31, 1998 to $2,185,387,000. The various issues comprising the outstanding debt are as follows (in thousands of dollars):

	December 31,	
	1998	*1997*
• **SERIES 1985B**		
6% maturing in 2020 with annual sinking fund requirements beginning in 2018	$ 80,575	$ 125,615
• **SERIES 1988**		
Zero coupon priced to yield 7.3% to 7.6% maturing annually from 2000 to 2003	11,052	11,052
6% maturing in 2015 with annual sinking fund requirements beginning in 2014		35,000
	11,052	46,052

	December 31, 1998	December 31, 1997
• **SERIES 1990**		
Zero coupon priced to yield 6.75% maturing in 2004	$ 3,670	$ 3,670
6.5% to 6.9% maturing annually from 1999 to 2003	7,790	8,745
6.5% maturing in 2010 with annual sinking fund requirements beginning in 2007	91,600	91,600
7% maturing in 2019 with annual sinking fund requirements beginning in 2014	10,225	10,225
	113,285	114,240
• **SERIES 1992**		
5.1% to 8% maturing annually from 1999 to 2011	472,815	490,335
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	135,495
6.2% maturing in 2018	83,540	83,540
5.75% maturing in 2020 with annual sinking fund requirements beginning in 2019	123,990	123,9[illegible]
6% Indexed Caps Bonds maturing in 2012	65,300	65,[illegible]
	1,123,285	1,189,6[illegible]
• **SERIES 1993**		
4.4% to 5.5% maturing annually from 1999 to 2010	223,165	243,995
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	103,390	103,390
5% maturing in 2018 with annual sinking fund requirements beginning in 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
	543,035	563,865
• **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**		
5% maturing annually from 1999 to 2001	8,015	8,725
5% to 5.125% maturing annually from 2009 to 2011	21,115	21,115
5.125% maturing in 2015	19,235	19,235
5.125% maturing in 2017 with annual sinking fund requirements beginning in 2016	57,425	57,4[illegible]
	105,790	106,500

	December 31, 1998	1997
• **SERIES 1998A**		
4.5% to 5.5% maturing annually from 1999 to 2015	$ 33,710	
5.125% maturing in 2017 with annual sinking fund requirements beginning in 2016	49,810	
5% maturing in 2020 with annual sinking fund requirements beginning in 2018	45,405	
	128,925	
	2,185,387	$2,225,402
Less: Current maturities of bonds	50,560	40,015
Unamortized discount	122,965	146,815
	$2,011,862	$2,038,572

The fair market value of the Agency's long-term debt was estimated using a yield curve derived from December 31, 1998 and 1997 market prices for similar maturities. 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 $2,276,149,000 and $2,294,189,000 at December 31, 1998 and 1997, respectively.

Certain proceeds of the Series 1985B, 1988, 1990, 1992, 1993, 1995A, 1997A, and 1998A bonds and the TECP were used to establish trusts for advance refunding of $3,367,905,000 of previously issued bonds. At December 31, 1998, $3,040,425,000 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 103%. 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. 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 103% of the respective principal amounts:

- Series 1985B *January 1, 1996*
- Series 1988 *January 1, 1998*
- Series 1990 *January 1, 2000*
- Series 1992 & 1993 *January 1, 2003*
- Series 1995A *January 1, 2006*
- Series 1997A *January 1, 2007*
- Series 1998A *January 1, 2008*

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.

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.

As a result of the 1998 refunding, the Agency increased costs of advanced refundings of debt by $26,003,000. However, the Agency will benefit from reduced debt service costs of $24,828,000 over the life of the Series 1998A bonds.

The following is a summary of debt service deposit requirements for bonds and Tax Exempt Commercial Paper outstanding at December 31, 1998 (in thousands of dollars). *See Table on next page.*

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 $50,560,000 at December 31, 1998 were collected through rates during 1998 and deposited monthly into the Bond Fund to make the January 1, 1999 principal payment.

F. TAX-EXEMPT COMMERCIAL PAPER

The Agency authorized and has issued $200,600,000 of TECP to accomplish the refunding of $217,055,000 in bonds. As of December 31, 1998 the Agency had $200,600,000 of TECP outstanding with an average maturity of 99 days and an average interest cost of 3.753%. The Agency maintains a direct-pay letter of credit with two banks for $205,546,000 that is drawn upon to provide funds to pay principal of and interest on the TECP when due, for which the Agency paid a fee of approximately $866,000 in 1998. Each draw upon the letter of credit is to be reimbursed from the proceeds of TECP issued on the same day the draw is made. In the event a draw is not reimbursed, it becomes a borrowing which matures four years after the termination date of the letter of credit agreement (currently December 7, 1999). There were no borrowings under the letter of credit agreement at December 31, 1998.

G. 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, 2001, and is automatically renewed

DEBT SERVICE DEPOSIT REQUIREMENTS FOR BONDS AND TAX EXEMPT COMMERCIAL PAPER

Year	*Principal*	*Interest*	*Total*
• 1999	$ 54,943	$ 123,315	$ 178,258
• 2000	59,448	120,690	180,138
• 2001	59,508	117,683	177,191
• 2002	64,323	114,539	178,862
• 2003	68,280	111,038	179,318
• 2004	70,665	107,332	177,997
• 2005	87,235	103,405	190,640
• 2006	93,470	97,686	191,156
• 2007	99,725	91,780	191,505
• 2008	103,605	87,509	191,114
• 2009	108,465	83,067	191,532
• 2010	113,290	78,386	191,676
• 2011	119,240	72,830	192,070
• 2012	127,070	66,821	193,891
• 2013	131,630	59,976	191,606
• 2014	135,940	52,818	188,758
• 2015	147,400	45,692	193,092
• 2016	159,745	37,700	197,445
• 2017	170,540	29,432	199,972
• 2018	176,780	19,583	196,363
• 2019	184,125	9,687	193,812
Total	$2,335,427	$1,630,969	$3,966,396

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, 1998 and 1997, the Agency paid ElectriCities $3,984,000 and $4,517,000, respectively.

- ***Insurance***

The Price-Anderson Act limits the public liability for a nuclear incident at a nuclear generating unit to $9,800,000,000, 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 $88,000,000 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.

H. OTHER REVENUES

Other revenues include $1,294,000 and $1,300,000 in 1998 and 1997, respectively, which were received from Duke in settlement of arbitration issues.

I. SUBSEQUENT EVENTS

On March 16, 1999, the Agency entered into a forward hedge swap agreement related to the future refunding of a portion of the Series 1990 bonds totaling $88,600,000. On October 5, 1999, the Agency anticipates issuing variable rate debt. Based upon the swap agreement, beginning on January 1, 2000 the Agency will make semi-annual payments calculated at a fixed rate to the counter party to the swap. In return, the counter party makes payments to the Agency based on a variable rate index. The Agency will continue to pay interest to the new variable rate debt holders at the variable rates provided on the debt. However, during the term of the swap agreement, the Agency effectively pays a fixed rate on the debt. The Agency will be exposed to variable rates if the counter party to the swap defaults or if the swap is terminated. With appropriate notice, the Agency has the unilateral right to terminate the swap at its then-current market value upon 30 days notice to the counter party. A termination of the swap agreement may result in the Agency's making or receiving a termination payment.

REQUIRED SUPPLEMENTAL INFORMATION — YEAR 2000 ISSUE (unaudited)

Management is aware of the potentially significant implications of the Year 2000 issue for the Agency. The concerns are assuring the continued operations of the jointly owned generation facilities, maintaining the supply of electric power to participants, and fulfilling obligations under the bond resolution. Management's plan focuses on three main areas:

1. *The preparedness of Duke's generation and transmission facilities,*
2. *The continued functionality of the participants' distribution systems, and*
3. *The internal operations of the administrative offices of ElectriCities.*

The Agency maintains contact with Duke and its participants to stay abreast of where they stand regarding Y2K remediation.

ElectriCities completed its assessment and remediation of in-house corporate business systems in December 1996, and has been working to complete preparation of all non-business computer systems by April 1999. Testing of all computer systems under the control of the Management Information Services Department (MIS) has been completed and is approximately 75% complete for the other areas that fall outside of the MIS department. However, completion of these remediation efforts does not guarantee that these systems will be Y2K compliant.

Management is committed to expend whatever it takes to address this issue. Thus far, the majority of the work has been performed by internal staff. Costs for external resources have been minimal. The pilot project and external expenses are expected to total approximately $200,000 for the life of the project. However, Management will continue to review budget needs and will not limit efforts due to external costs.

SCHEDULE OF CHANGES IN Assets OF FUNDS INVESTED ($000s)

	Funds Invested Jan. 1, 1997	Bond Proceeds	Power Billing Receipts	Investment Income	Disbursments	Transfers
Bond Fund:						
Interest account	$ 63,108	$ (1,911)	$ 0	$ 1,521	$(124,478)	$121,342
Reserve account	180,656			12,083		(11,906)
Principal account	43,458	(1,428)		1,051	(43,240)	40,658
	287,222	(3,339)		14,655	(167,718)	150,094
Reserve & Contingency Fund	18,513			1,849	(5,562)	3,601
Special Reserve Fund	1,024			76		(73)
Revenue Fund:						
Revenue account	41,335	(17,701)		1,424	55,107	(227,915)
Rate stabilization account	365,819		167,039	23,791	(3,173)	(40,060)
	407,154	(17,701)	167,039	25,215	51,934	(267,975)
Operating Fund:						
Working capital account	30,338			6,321	(162,646)	162,340
Fuel account	84,136					(13,879)
	114,474			6,321	(162,646)	148,461
Supplemental Fund:						
Supplemental account	20,472		78,490	1,416	(11,625)	(63,119)
Supplemental reserve account	34,125			2,918		29,011
	54,597		78,490	4,334	(11625)	(34,108)
	$882,984	$(21,040)	$245,529	$52,450	$(295,617)	$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, 1998 and 1997, respectively.

See accompanying Independent Auditors' Report.

SCHEDULE OF CHANGES IN Assets OF FUNDS INVESTED ($000s)

Funds Invested Dec. 31, 1997	Bond Proceeds	Power Billing Receipts	Investment Income	Disbursements	Transfers	Funds Invested Dec. 31, 1998
$ 59,582	$ 868	$ 0	$ 1,408	$(118,704)	$115,932	$ 59,086
180,833	4,061		11,756	(4,382)	(10,897)	181,371
40,499			1,286	(40,015)	49,024	50,794
280,914	4,929		14,450	(163,101)	154,059	291,251
18,401	406		1,942	(6,155)	3,484	18,078
1,027			39	(74)	50	1,042
36,990	310	177,630	1,733	27,209	(218,443)	25,429
328,676	(7,588)		21,584	3,831	(36,278)	310,225
365,666	(7,278)	177,630	23,317	31,040	(254,721)	335,654
36,353			5,938	(121,858)	112,188	32,621
70,257					16,681	86,938
106,610			5,938	(121,858)	128,869	119,559
25,634		79,433	975	(25,754)	(54,267)	26,021
66,054			4,813		22,526	93,393
91,688		79,433	5,788	(25,754)	(31,741)	119,414
$864,306	$(1,943)	$257, 063	$51,474	$(285, 902)	$ 0	$884,998

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, 1998 and 1997, respectively.

See accompanying Independent Auditors' Report.

SCHEDULE OF Revenues AND EXPENSES

PER BOND RESOLUTION AND OTHER AGREEMENTS ($000s)

	Year Ended December 31, 1998			Year Ended December 31, 1997		
	Project	*Supplemental*	*Total*	*Project*	*Supplemental*	*Total*
REVENUES:						
Sales of electricity to participants	$188,903	$68,365	$257,268	$169,321	$76,846	$246,167
Sales of electricity to utilities	102,551		102,551	119,698		119,698
Other revenues	1,312		1,312	1,265		1,265
Rate stabilization fund withdrawal	29,067		29,067	40,897		40,897
Fund valuations	12,912		12,912	9,829		9,829
Investment revenue available						
for operations	25,061	1,124	26,185	24,053	4,411	28,464
	359,806	69,489	429,295	365,063	81,257	446,320
EXPENSES:						
Operation & maintenance	73,830		73,830	80,818		80,818
Nuclear fuel	24,040		24,040	25,301		25,301
Interconnection services:						
Purchased power	21,941	27,250	49,191	17,026	30,144	47,170
Transmission & distribution		12,980	12,980		12,934	12,934
Other		192	192		134	1[illegible]
	21,941	40,422	62,363	17,026	43,212	60,2[illegible]
Administrative & general-Duke	18,929		18,929	28,187		28,187
Administrative & general-Agency	2,749	2,930	5,679	2,607	2,900	5,507
Miscellaneous Agency expense		1,228	1,228		1,493	1,493
Gross receipts and excise taxes	8,534	2,254	10,788	7,838	2,447	10,285
Property tax	12,866		12,866	12,963	2	12,965
Debt service	176,712	127	176,839	171,277	117	171,394
Special funds deposits:						
Decommissioning fund	3,210		3,210	2,786		2,786
Reserve and contingency fund	16,995		16,995	16,260		16,260
Supplemental reserve fund		22,528	22,528		31,086	31,086
	20,205	22,528	42,733	19,046	31,086	50,132
	359,806	69,489	429,295	365,063	81,257	446,320
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, 1998 and 1997, respectively.

See accompanying Independent Auditors' Report.

NCMPA1 STATISTICAL Highlights

TEN YEARS AT A GLANCE

	1998	1997	1996	1995	1994
• Megawatt-hour Sales (MWH)	4,496,603	4,223,699	4,221,890	4,125,029	3,950,370
• Peak Billing Demand (kW)	842,892	853,384	829,245	803,615	752,717
• Operating Revenues	$361,131,000	$367,130,000	$375,577,000	$413,852,000	$540,695,000*
• Excess of Revenues over Expenditures	$0	$0	$0	$0	$0
• Sales to Duke (Revenues)	$102,551,000	$119,698,000	$134,453,000	$183,554,000	$237,153,000
• Average Monthly Power Purchases by Cities (MWh)	374,717	351,975	351,824	343,752	329,198
• Average Monthly Billings by Cities	$21,439,000	$20,514,000	$19,942,000	$19,077,000	$17,711,000

	1993	1992	1991	1990	1989
• Megawatt-hour Sales (000)	3,976,104	3,757,172	3,722,099	3,585,461	3,572,021
• Peak Billing Demand (kW)	788,060	740,847	742,108	721,247	689,304
• Operating Revenues	$443,511,000	$418,234,000	$438,810,000	$432,647,000	$429,098,000
• Excess (Deficiency) of Revenues over Expenditures	$3,121,000	$(5,799,000)	$(12,544,000)	$(18,534,000)	$19,167,000
• Sales to Duke (Revenues)	$238,954,000	$234,625,000	$262,456,000	$266,086,000	$263,034,000
• Average Monthly Power Purchases by Cities (MWh)	331,342	313,098	310,175	298,788	297,668
• Average Monthly Billings by Cities	$17,046,000	$15,301,000	$14,696,000	$13,880,000	$13,839,000

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

North Carolina EASTERN
MUNICIPAL POWER AGENCY

CHAIRMAN'S LETTER TO STAKEHOLDERS

Frederick E. Turnage
Chairman, NCEMPA

In the not so distant past, only those directly involved in the business of the electric utility industry in North Carolina either knew of or shared concern about the issues affecting an organization called North Carolina Eastern Municipal Power Agency. Today, as I reflect on our efforts this past year, I do so with conviction and appreciation to those who have worked diligently to tell our story. It is a complicated and formidable one.

The year started befittingly with a presentation on the history of the Power Agencies to the Legislative Study Commission on the Future of Electric Service in North Carolina as the state embarked on a comprehensive study of the power industry. Throughout the year, considerable and purposeful efforts centered on furthering the cause of public power to lawmakers and key stakeholders. By year's end, two clear issues resonated loudly on behalf of the "electric cities." First, a rate disparity exists between the Power Agency cities and the private utilities. And that without swift and reasonable resolution to this growing chasm in rates, adverse economic impact will be the consequence statewide.

This is indeed an onerous legacy. Nonetheless, there is also much to celebrate.

Power Agency participants and staff continued efforts to prepare for competition as the industry moves toward deregulation, staying focused on initiatives to lower power costs including refinancing opportunities and redoubled efforts to enhance current operations. Among the laudable achievements for Eastern Agency is the finalization of a contract for a new resource for supplemental power purchases with Carolina Power & Light Co. Beginning in January 1999 and over the next five years, participants will benefit from an expected $30 million in savings from power supply expenses. Considerable attention, too, was focused on load management, Y2K readiness, clean air requirements and new business development initiatives.

It has been a good year for economic development. Power Agency cities across Eastern North Carolina enjoyed a remarkable year. Expansion and recruitment efforts over the year have or will land some 2,600 new jobs to participant communities, adding more than 12.5MW of new electric load and $87 million in capital investments.

Also during 1998, NCEMPA municipal systems once again responded swiftly during emergency weather disasters including Hurricane Bonnie and the Christmas Eve ice storms. Utility crews braved the elements, working tirelessly to restore power and bring comfort to their own and neighboring communities. Dedication and more than 100 years of utility experience is evident each time our cities are called to respond.

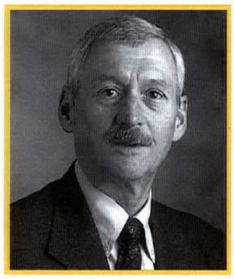
Before we can embark on a new chapter for public power, it is that experience, that dedication that must be acknowledged. And of one individual in particular, Peter G. Vandenburg, NCEMPA's Vice Chairman of the Board of Commissioners, who retired in December. Throughout his 30-year career of public service in North Carolina, Pete has demonstrated loyalty and commitment to furthering the cause of public power. His remarkable career has spanned a dynamic and challenging history for our electric cities, and we are stronger for having his participation and leadership. As Pete takes a new course in his personal endeavors, we wish him great success.

Like Pete, public power is at a crossroads. New opportunities are on the horizon. Others have yet to be realized. While the road ahead may be unfamiliar, our hands are steady at the wheel.

NCEMPA Board OF COMMISSIONERS

AS OF DECEMBER 31, 1998

Frederick E. Turnage
Chairman
Mayor, Rocky Mount



Peter G. Vandenberg
Vice Chairman
City Manager, Laurinburg

Anne-Marie Knighton
Secretary-Treasurer
Town Manager, Edenton

1998 OFFICERS

COMMISSIONERS

- **Mr. William M. Sutton**
  Town Manager
  Apex
- **Mr. Jimmy G. Westbrook**
  Electrical Engineer
  Ayden
- **Mr. Timothy M. Johnson**
  Town Manager
  Belhaven
- **Mr. Keith R. Langdon**
  Town Manager
  Benson
- **Mr. Robert Ahlert**
  Council Member
  Clayton
- **Ms. Anne-Marie Knighton**
  Town Manager
  Edenton
- **Mr. Steven L. Harrell**
  City Manager
  Elizabeth City
- **Mr. Richard N. Hicks**
  Town Manager
  Farmville
- **Vacant**
  Fremont
- **Ms. Valerie J. Dixon**
  GUC Commissioner
  Greenville
- **Mr. Herman T. Etheridge**
  Commissioner
  Hamilton
- **Mr. John Christensen**
  Town Manager
  Hertford
- **Mr. J. W. Bryant, Jr. *(Deceased)***
  Mayor
  Hobgood
- **Mr. R. Scott Spence**
  Town Commissioner
  Hookerton
- **Mr. David R. Walker**
  Interim City Manager
  Kinston
- **Mr. Mike Taylor**
  Town Manager
  LaGrange
- **Peter G. Vandenberg**
  City Manager
  Laurinburg
- **Mr. C. L. Gobble**
  Town Administrator
  Louisburg
- **Mr. Harry L. Ivey**
  Council Member
  Lumberton
- **Mr. Ralph E. Puckett**
  Dir. of Electrical Utilities
  New Bern
- **Mr. Lyman Galloway**
  Town Commissioner
  Pikeville
- **Mr. John McNeill**
  Town Commissioner
  Red Springs
- **Mr. John Pritchard, Jr.**
  Town Manager
  Robersonville
- **Mr. Frederick E. Turnage**
  Mayor
  Rocky Mount
- **Mr. James E. Walden**
  Town Commissioner
  Scotland Neck
- **Mr. Bruce A. Radford**
  City Manager
  Selma
- **Vacant**
  Smithfield
- **Mr. Paul D. Fisher**
  Alderman
  Southport
- **Mr. Samuel W. Noble, Jr.**
  Town Manager
  Tarboro
- **Mr. Mark S. Williams**
  Town Manager
  Wake Forest
- **Mr. R. L. Willoughby**
  City Manager
  Washington
- **Mr. Edward A. Wyatt**
  City Manager
  Wilson

ALTERNATE COMMISSIONERS

- **Mr. J. Michael Wilson**
  Asst. Town Manager
  Apex
- **Mr. Edwin L. Booth**
  Town Manager
  Ayden
- **Vacant**
  Belhaven
- **Mr. Don H. Johnson**
  Mayor
  Benson
- **Mr. A. Cameron Mercer**
  Council Member
  Clayton
- **Mr. William A. Crummey**
  Director of Public Utilities
  Edenton
- **Mr. Zack D. Robertson**
  City Council Member
  Elizabeth City
- **Mr. J. Don Riddle**
  Utility Director
  Farmville
- **Mr. Billy Harvey**
  Alderman
  Fremont
- **Ms. Nancy M. Jenkins**
  Mayor
  Greenville
- **Mr. Malcolm A. Green**
  GUC General Manager
  Greenville
- **Mr. D. G. Matthews III**
  Mayor
  Hamilton
- **Mr. John G. Beers**
  Mayor
  Hertford
- **Mr. J. A. Whitehurst, Jr.**
  Town Commissioner
  Hobgood
- **Vacant**
  Hookerton
- **Mr. Carey B. Washburn**
  Kinston
- **Mr. Ronald D. Wicker**
  Dir. of Public Utilities
  Kinston
- **Mr. Jerry W. Woodall**
  Council Member
  LaGrange
- **Ms. Ann B. Slaughter**
  Mayor
  Laurinburg
- **Ms. Lois Brown Wheless**
  Council Member
  Louisburg
- **Mr. Ray Patterson**
  Director of Electrical Services
  Louisburg
- **Vacant**
  Lumberton
- **Mr. Walter B. Hartman, Jr.**
  City Manager
  New Bern
- **Mr. Robert W. Davy**
  Town Administrator
  Pikeville
- **Mr. T. Wayne Horne**
  Town Manager
  Red Springs
- **Mr. John David Jenkins**
  Town Commissioner
  Robersonville
- **Mr. Stephen W. Raper**
  City Manager
  Rocky Mount
- **Mr. Russell Tutor**
  Town Administrator
  Scotland Neck
- **Vacant**
  Selma
- **Mr. Robert E. Tripp III**
  Dir. of Public Utilities
  Smithfield
- **Mr. Robert E. "Ed" Honeycutt**
  Public Services Director
  Southport
- **Mr. Ricky C. Page**
  Utility Director
  Tarboro
- **Mr. T. G. Allgood, Jr.**
  Council Member
  Tarboro
- **Mr. Al S. Hinton**
  Town Commissioner
  Wake Forest
- **Mr. Keith Hardt**
  Electric Utility Director
  Washington
- **Mr. Charles W. Whitley, Jr.**
  Dir. of Public Utilities
  Wilson
- **Mr. Charles W. Pittman, III**
  Deputy City Mgr.-Operations & Public Serv.
  Wilson

Participants ELECTRIC SYSTEMS

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY

City/Town	Established	Customers	Revenues	% Ownership
Apex	1917	5,568	*1998* – $9,202,792 *1997* – $7,207,802	0.7056
Ayden	1916	3,509	*1998* – $7,687,062 *1997* – $7,560,389	1.1340
Belhaven	1920	1,221	*1998* – $2,272,340 *1997* – $2,168,243	0.4090
Benson	1913	1,779	*1998* – $3,499,980 *1997* – $3,365,928	0.5773
Clayton	1913	3,480	*1998* – $6,327,348 *1997* – $5,889,889	0.7448
Edenton	1908	3,828	*1998* – $8,162,432 *1997* – $7,925,392	1.5961
Elizabeth City	1926	10,400	*1998* – $22,949,100 *1997* – $22,264,316	4.2510
Farmville	1904	2,844	*1998* – $5,003,219 *1997* – $4,781,364	1.2901
Fremont	1918	936	*1998* – $1,308,865 *1997* – $1,240,220	0.3062
Greenville	1905	47,787	*1998* – $108,453,063 *1997* – $102,233,721	16.1343
Hamilton	1922	255	*1998* – $407,666 *1997* – $398,272	0.0783
Hertford	1915	1,275	*1998* – $2,216,358 *1997* – $2,322,891	0.4124
Hobgood	1922	349	*1998* – $463,649 *1997* – $434,566	0.0913
Hookerton	1907	390	*1998* – $646,873 1997- $600,001	0.1550
Kinston	1897	17,111	*1998* – $37,388,617 *1997* – $35,808,929	8.6678
La Grange	1917	1,478	*1998* – $2,333,428 *1997* – $2,285,679	0.5014
Laurinburg	1925	5,494	*1998* – $11,865,678 *1997* – $11,897,667	2.2675
Louisburg	1906	1,919	*1998* – $5,171,017 *1997* – $5,147,955	0.8577
Lumberton	1915	8,750	*1998* – $22,101,488 *1997* – $21,564,885	5.1568
New Bern	1901	15,663	*1998* – $37,820,092 *1997* – $35,457,773	6.3676
Pikeville	1918	545	*1998* – $792,737 *1997* – $850,330	0.2046
Red Springs	1910	1,890	*1998* – $3,004,767 *1997* – $2,889,549	0.5798
Robersonville	1919	1,154	*1998* – $2,329,438 *1997* – $2,215,589	0.5066
Rocky Mount	1902	27,462	*1998* – $64,610,622 *1997* – $63,537,709	16.0260
Scotland Neck	1903	1,693	*1998* – $3,002,646 *1997* – $3,056,336	0.5762
Selma	1913	2,552	*1998* – $5,148,051 *1997* – $4,931,634	0.8102
Smithfield	1912	4,459	*1998* – $12,218,238 *1997* – $11,494,814	2.0056
Southport	1916	1,904	*1998* – $3,455,933 *1997* – $3,296,365	0.7139
Tarboro	1897	5,816	*1998* – $20,004,916 *1997* – $21,381,822	4.7427
Wake Forest	1909	4,380	*1998* – $7,619,626 *1997* – $6,859,693	0.7262
Washington	1903	12,046	*1998* – $23,508,073 *1997* – $22,440,132	5.8920
Wilson	1892	29,423	*1998* – $91,089,102 *1997* – $88,508,473	15.5120

PLANT STATUS

Standard plant operations for NCEMPA in 1998 were augmented by record-breaking generation and performance at the Brunswick and Harris Plants, in spite of complications from Mother Nature.

The combined operation of Units 1 and 2 at Brunswick produced the most net energy (combined unit net generation) in a one-year period, breaking the previous record set in 1997. In addition, Brunswick Unit 2 set the plant's single-unit all time high net generation record in 1998, topping the 1997 record. The generation records were set in spite of a refueling outage on Unit 1, and the effects of Hurricane Bonnie.

As Hurricane Bonnie traveled at a leisurely pace through the eastern part of the state in August, she stalled over the town of Southport and the Brunswick Plant for two days. As a safety precaution, in accordance with Nuclear Regulatory Commission requirements, both units were put into "cold shutdown" at least two hours before hurricane force winds reached the plant site, and the plant sustained only minor damage. Seventeen of NCEMPA's participant cities reported 46,000 outages. The cities worked efficiently to have power restored to 38,000 customers within 48 hours. Full power was restored after three days.

The Harris Plant set a few records of its own in 1998. It had the longest continuous run in plant history, operating for more than 400 days without an outage. The plant also completed its best refueling outage in plant history; one that lasted 35 days and 23 hours. A steam generator replacement project is scheduled to begin at Harris in 2001. One of the three steam generators to be installed arrived at the plant in late 1998.

The Harris and Brunswick plants maintained excellent safety records in 1998, according to the federal Nuclear Regulatory Commission, the Institute of Nuclear Power Operations and the World Association of Nuclear Power Operators.

PLANT INFORMATION*

	Capacity Factor %	*Availability Factor %*
• Harris 1	89.09	88.42
• Brunswick 1	88.55	86.92
• Brunswick 2	98.02	95.82
• Mayo 1	65.86	91.13
• Roxboro 4	65.15	91.93

** Source: CP&L*

ENERGY AND DEMAND

While most of the year's temperatures were in the mild to average range, cities had the highest demand for energy ever (685,635,316 Kwh) during the month of July. In addition, July produced the highest coincident peak (1,344,823 KW) in the Agency's history. NCEMPA's average monthly coincident peak load factor was more than 83 percent. *(See tables, Page 44)*

NEGOTIATIONS WITH CP&L

An Agency agreement with CP&L, which was initiated in 1996, whereby the Agency concurred to delay the construction of its peaking project, went into effect in June 1998. This agreement states that NCEMPA will delay building two combustion turbine units to generate power needed during peak demand periods. The Agency has agreed to postpone this project and continue purchasing power from CP&L at a rate that is comparable to the cost of generating the power from its own units. This agreement relates to the peaking project and will be effective through December 2003. It will save NCEMPA $41 million in power costs over five years.

NCEMPA re-negotiated a contract with CP&L to re-price supplemental capacity. The agreement is effective from January 1999 through 2002, with an option to extend through 2003 and several options to procure power at market-based rates thereafter. Savings to NCEMPA members are projected to be $30 million during the term of the agreement.

ECONOMIC DEVELOPMENT

The Power Agency continued economic development credits as an incentive to encourage new retail customers in member cities' service areas. Agency staff can provide meter reading, as well as data processing and credit calculation for members to provide credits to these customers. NCEMPA cities have added more than 20 new loads, totaling more than 12,000 MWh per month in retail sales that are eligible to receive credits.

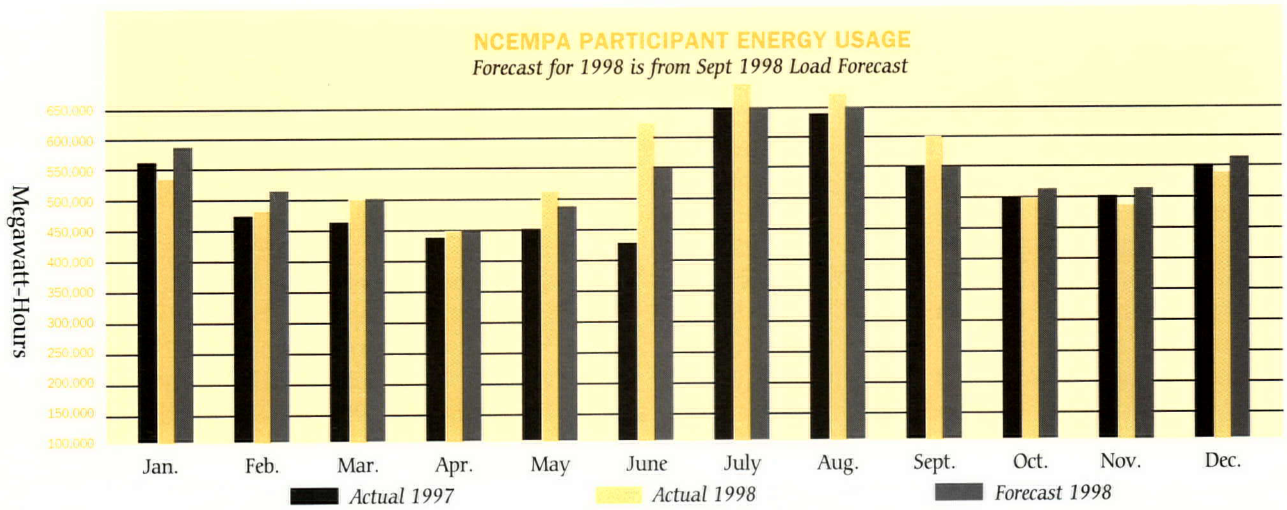
NCEMPA's efforts to secure new industrial and commercial customers in 1998 will generate 2,600 new jobs, 12.5 MW of new load and $87 million in expansion investments within member cities. Although several cities lost a total of four satellite customers, the additional business generated through economic development more than offset this.

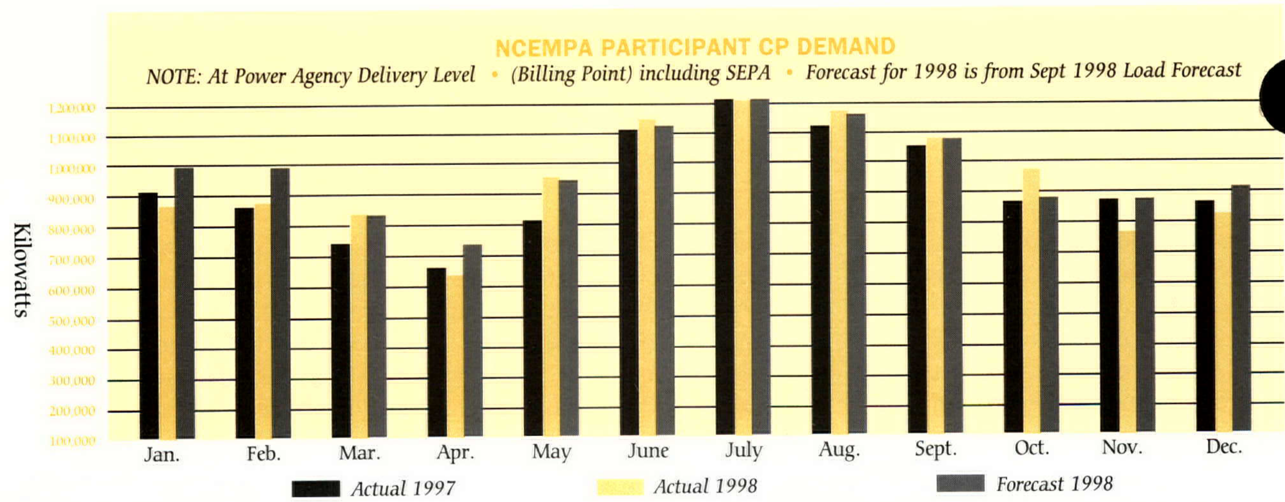
As part of the Retail Rate Assistance Program, successful customer presentations and competitive rate designs enabled eight participants to secure new customers and prevail in

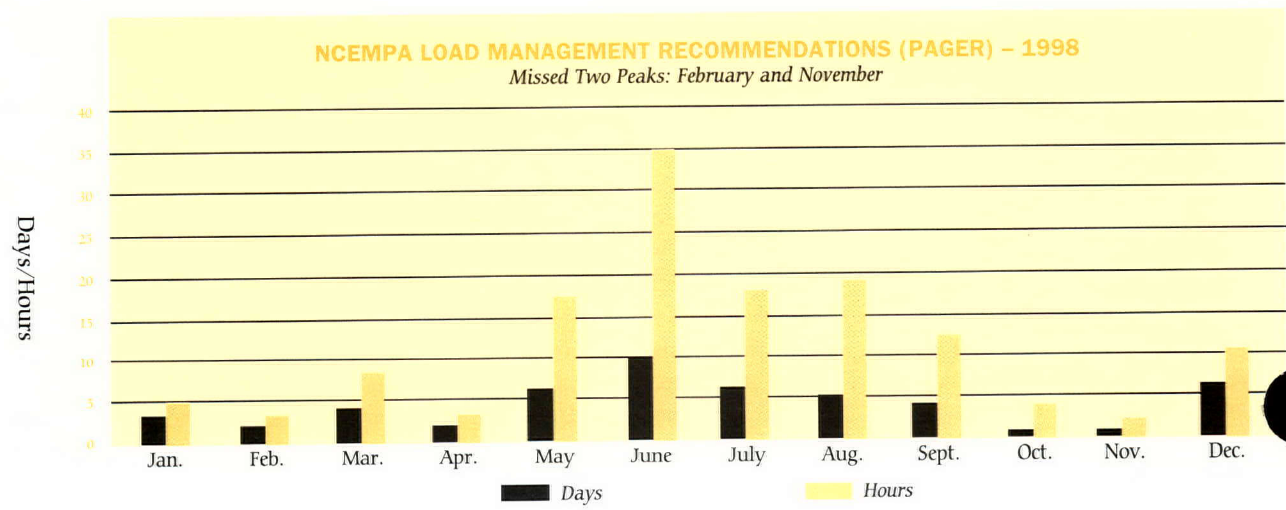
CONTINUED

Operational HIGHLIGHTS

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY







customer choice situations during 1998. Agency staff also conducted four full rate studies and five partial studies for the Agency's membership. As of December 1998, 29 of 32 participants offer innovative or load management incentive rates, and all 32 cities provide load management opportunities to their customers.

NEW SERVICES

The Agency maintained existing cost-saving programs for its participants, and implemented several new systems designed to support the cities in their service to customers.

A participant billing service was implemented for the members and is currently providing retail metering and billing assistance to 13 cities for more than 50 commercial and industrial accounts. Under this program NCEMPA staff assist cities with metering, meter reading, data processing and the preparation of electric bills using the cities' retail rates.

After more than 18 months of development, installation and testing, the Load Management Monitoring System (LMMS) became a reality for NCEMPA and eight participant cities in 1998. This system - proposed by the cities in 1996 - promotes an information exchange about loads and load management activities that enables NCEMPA and its cities to provide more effective load management strategies and operations to all cities and retail customers.

Pilot programs in Kinston, Tarboro and Washington were conducted to determine how customers would receive new energy services programs. The viability of the new programs was also tested in Fayetteville, High Point, Lexington and Monroe. The successful results of the pilot programs solidified an agreement between NCEMPA and Honeywell Inc. to offer services to improve energy efficiency, operations and overall performance. This alliance will be implemented in 1999.

LOAD MANAGEMENT OPERATIONS

Load management recommendations by NCEMPA staff resulted in hitting 10 out of 12 peaks for 1998. The peak for February was shifted due to load management and customers still realized a savings. The November peak was missed due to unusually mild weather conditions that month. *(See tables, Page 44)*

Agency staff conducted more than 20 audits for commercial and industrial customers, and identified cost reduction and load management opportunities for these customers and member cities. More than 400 pagers/radio service units have been issued to the cities' staff and customers to streamline communications. Overall, load management operations resulted in a savings of more than $3 million per month, and approximately $36 million in savings for the year.

YEAR 2000 PREPARATION

NCEMPA accelerated its preparation for the new millennium, and the Agency is on schedule to complete all remediation of its internal systems by the end of the first quarter in 1999. Throughout the year, NCEMPA worked to increase general awareness about this issue, and educated the cities about how to address it locally. A renewed emphasis was placed on supporting the cities' Y2K preparation efforts. NCEMPA is monitoring the progress of CP&L and VEPCO, as the year 2000 approaches, and keeping the cities informed about the status of these vendors' Y2K readiness.

NCEMPA launched a pilot project in New Bern to examine how the turnover to the year 2000 may effect the delivery of electric service. Overall, the results were very positive. Only 15 items were found to be non-compliant out of an inventory of 372 microprocessor items, and none of these items are integral to the electrical distribution systems. All 15 items needing repair or replacement to be Y2K ready were in personal computers' software or hardware. The embedded microprocessor chips found in the electric distribution system in New Bern were found to be Y2K ready. These findings support recent reports that the embedded systems may not be as problematic as previously thought, in general, and with electric distribution systems, in particular, in comparison to generation facilities. The pilot project served as an important benchmark in determining the potential magnitude of the Year 2000 problems facing the NCEMPA cities.

The message to prepare for Y2K was taken to the cities during a series of educational summits, sponsored by NCEMPA and ElectriCities. The summits were well-attended, and indicated that the majority of the cities were well on their way toward Y2K readiness. NCEMPA will continue to assist and support the cities with their year 2000 efforts to ensure readiness by Summer 1999.

The Board of Directors for ElectriCities formally adopted the company's Year 2000 Readiness Plan. The schedule outlined in the plan is similar to one adopted by North American Electric Reliability Council (NERC). ElectriCities and NCEMPA have entered the final stages of the process, and have participated in discussions on contingency planning with the Southeastern Reliability Council.

Financial INFORMATION

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY

INVESTMENT PORTFOLIO STATISTICS

- **Earnings**

*Earnings**	*Income*	*Rate of Return*
1998	$44,156,000	6.64%
1997	$44,353,000	6.67%

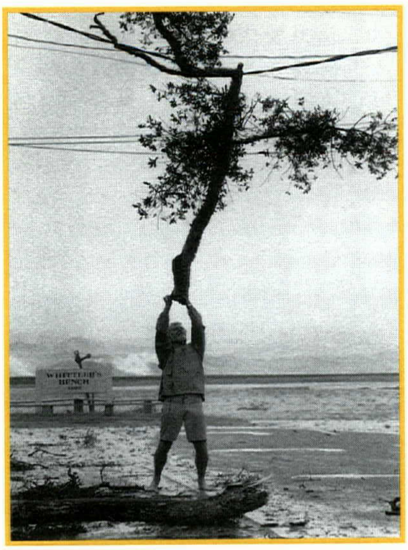
- **Market Value as of 12/31***

	Value	*Average Maturity*
1998	$778,418,000	4.1 years
1997	$767,258,000	3.8 years

- **Transactions**

	Number	*Amount*
1998	897	$7,562,555,000
1997	871	$8,086,797,000

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



DEBT STATISTICS

- **Debt Outstanding 12/31**

	Balance (Thousands)	*Weighted Average Interest Cost*
Fixed Rate Bonds		
1998	$3,193,996**	6.21%
1997	$3,234,845**	6.19%
Variable Rate Bonds		
1998	$155,000	3.98%
1997	$155,000	4.56%
Tax-Exempt Commercial Paper		
1998	$137,000	3.94%
1997	$137,000	4.50%

*** Does not include $643,000 and $551,000 for 1998 and 1997, respectively, accrued on the balance sheet for current maturities of the series 1998A Capital Appreciation Bonds or $289,000 for 1998 for the series 1989A Capital Appreciation Bonds.*

In preparing for Hurricane Bonnie's arrival, the Brunswick plant was shut down as a safety precaution. That made it possible for Southport resident Freddie Smartley to wrestle this limb from a power line at the height of the storm.

Photo courtesy of Jim Harper, State Port Pilot, Southport

NCEMPA BOND RECONCILIATION

Bonds Outstanding 12/31/97		$3,389,845,000**
Matured 1/1/98	-	40,599,000
Redeemed	-	250,000
Bonds Outstanding 12/31/98		$3,348,996,000**

NCEMPA BONDS OUTSTANDING

Series 1985G	$ 95,565,000
Series 1986A	4,495,000
Series 1988A	29,710,000**
Series 1988B	155,000,000
Series 1989A	215,560,000**
Series 1991A	330,021,000
Series 1993A	108,610,000
Series 1993B	1,485,200,000
Series 1993C	311,935,000
Series 1993D	80,000,000
Series 1995A	62,295,000
Series 1996A	302,125,000
Series 1996B	136,875,000
Series 1997A	31,605,000

INDEPENDENT Auditors' REPORT

NORTH CAROLINA EASTERN MUNICIPAL POWER AGENCY BOARD OF DIRECTORS

We have audited the accompanying balance sheets of North Carolina Eastern Municipal Power Agency as of December 31, 1998 and 1997 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 generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North Carolina Eastern Municipal Power Agency at December 31, 1998 and 1997, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

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 Schedule of Revenues and Expenses per Bond Resolution and Other Agreements and Schedule 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.

The year 2000 supplementary information on page 67 is not a required part of the general purpose financial statements, but is supplementary information required by the Governmental Accounting Standards Board, and we did not audit and do not express an opinion on such information. Further, we were unable to apply to the information certain procedures prescribed by professional standards because of the nature of the subject matter underlying the disclosure requirements and because sufficiently specific criteria regarding the matters to be disclosed have not been established. In addition, we do not provide assurance that North Carolina Eastern Municipal Power Agency is or will become year 2000 compliant, that North Carolina Eastern Municipal Power Agency's year 2000 remediation efforts will be successful in whole or in part, or that parties with which North Carolina Eastern Municipal Power Agency does business are or will become year 2000 compliant.

KPMG LLP

RALEIGH, NORTH CAROLINA • APRIL 16, 1999

Balance SHEETS
($000s)

ASSETS	December 31, 1998	1997
• Electric Utility Plant (Note C):		
Electric plant in service, net of accumulated depreciation of $533,776 and $493,377	$876,149	$921,468
Construction work in progress	5,290	430
Nuclear fuel, net of accumulated amortization of $36,739 and $37,404	29,291	28,781
	910,730	950,679
• Non-Utility Property and Equipment, net (Note C)	1,986	1,921
• Special Funds Invested (Notes D and G):		
Construction fund	123,917	130,740
Bond fund	361,987	360,660
Reserve and contingency fund	23,694	23,463
Decommissioning fund	4,380	3,789
Special reserve fund	1,087	1,043
	515,065	519,695
• Trust for Decommissioning Costs	70,082	57,132
• Operating Assets:		
Funds invested (Notes D and G):		
Revenue fund	103,184	88,170
Operating fund	37,488	51,166
Supplemental fund	58,919	58,855
	199,591	198,191
Participant accounts receivable	32,499	34,712
Fossil fuel inventory	5,169	3,450
Prepaid expenses	10,662	9,329
	247,921	245,682
• Deferred Costs:		
Unamortized debt issuance costs	42,563	44,422
VEPCO compensation payment (Note E)	8,939	9,328
Development costs	6,353	6,622
Costs of advance refundings of debt	510,445	547,142
Net costs to be recovered from future billings to participants (Note F)	1,270,243	1,237,121
	1,838,543	1,844,635
	$3,584,327	$3,619,744

SEE NOTES TO FINANCIAL STATEMENTS.

BALANCE Sheets
($000s)

LIABILITIES AND RETAINED EARNINGS	December 31, 1998	1997
• Long-Term Debt:		
Bonds, net of unamortized discount (Note G)	$3,206,506	$3,246,402
• Special Funds Liabilities:		
Construction payables		683
Current maturities of bonds (Note G)	42,270	41,150
Accrued interest on bonds	103,099	102,852
Tax-exempt commercial paper (Note H)	137,000	137,000
Accrued interest on commercial paper	924	834
	283,293	282,519
• Liability for Decommissioning Costs	58,261	48,526
• Operating Liabilities:		
Accounts payable	7,969	10,837
Accrued taxes	4,974	5,460
	12,943	16,297
• Commitments and Contingencies (Notes C, H, I, J, and K)		
• Retained Earnings	23,324	26,000
	$3,584,327	$3,619,744

SEE NOTES TO FINANCIAL STATEMENTS.

SCHEDULE OF Revenues AND EXPENSES

AND CHANGES IN RETAINED EARNINGS ($000s)

	Year Ended December 31, 1998	1997
Operating Revenues:		
Sales of electricity to participants	$414,462	$408,600
Sales of electricity to utilities	35,027	38,142
	449,489	446,742
Operating Expenses:		
Operation and maintenance	39,113	42,660
Fuel	37,340	38,194
Power coordination services:		
Purchased power	94,889	96,680
Transmission and distribution	17,677	16,976
Other	85	93
	112,651	113,749
Administrative and general	26,035	28,281
Amounts in lieu of taxes	3,925	4,352
Gross receipts tax	13,234	13,054
Depreciation and amortization	52,062	52,781
	284,360	293,071
Net Operating Income	165,129	153,671
Interest Charges (Credits):		
Interest expense	203,691	207,314
Amortization of debt refunding costs	36,672	35,803
Amortization of debt discount and issuance costs	3,698	3,684
Investment income	(37,868)	(48,321)
Net increase in fair value of investments	(5,036)	(7,185)
Net interest capitalized	(230)	
	200,927	191,295
Net Costs to be Recovered from Future Billings to Participants (Note F)	33,122	37,624
(Deficiency) Excess of Revenues Over Expenses	(2,676)	0
Retained Earnings, Beginning of year	26,000	26,000
Retained Earnings, End of year	$23,324	$26,000

SEE NOTES TO FINANCIAL STATEMENTS.

STATEMENTS OF Cash FLOWS
($000s)

	Year Ended December 31, 1998	1997
Cash Flows from Operating Activities:		
Receipts from sales of electricity	$ 451,734	$ 446,182
Payments of operating expenses	(219,742)	(226,338)
Net cash provided by operating activities	231,992	219,844
Cash Flows from Capital and Related Financing Activities:		
Bonds issued		31,640
Bonds refunded		(35,000)
Interest paid	(202,412)	(196,895)
Refunding Trust Fund requirement		(1,798)
Debt discount and issuance costs paid	(131)	(1,679)
Additions to electric utility plant and non-utility property and equipment	(26,651)	(21,035)
Bonds retired or redeemed	(41,400)	(23,830)
Investment earnings receipts from construction fund	1,456	1,652
Net cash used for capital and related financing activities	(269,138)	(246,945)
Cash Flows from Investing Activities:		
Sales and maturities of investment securities	7,431,798	8,047,941
Purchases of investment securities	(7,430,909)	(8,063,484)
Investment earnings receipts from non-construction funds	36,275	42,647
Net cash provided by investing activities	37,164	27,104
Net Increase in Operating Cash	18	3
Operating Cash, Beginning of year	5	2
Operating Cash, End of year	$ 23	$ 5

SEE NOTES TO FINANCIAL STATEMENTS.

STATEMENTS OF CASH Flows (CONT.)

($000s)

	Year Ended December 31, 1998	1997
Reconciliation of Net Operating Income to Net Cash Provided by Operating Activities:		
Net Operating Income	$165,129	$153,671
Adjustments:		
Depreciation and amortization	52,062	52,782
Amortization of nuclear fuel	16,679	16,480
Changes in assets and liabilities:		
Decrease (increase) in participant accounts receivable	2,213	(772)
Increase in fossil fuel stock	(1,719)	(811)
(Increase) decrease in prepaid expenses	(1,333)	24
Decrease in deferred costs	658	660
Decrease in accounts payable	(1,211)	(2,031)
Decrease in accrued taxes	(486)	(159)
Total Adjustments	66,863	66,173
Net Cash Provided by Operating Activities	$231,992	$219,844

SEE NOTES TO FINANCIAL STATEMENTS.

NOTES TO Financial STATEMENTS

YEARS ENDED DECEMBER 31, 1998 AND 1997

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.

The Agency also entered into the Power Coordination Agreement (1981 PCA) with CP&L whereby the Agency purchases power in excess of that received through the initial project and the Southeastern Power Administration (SEPA), in order to meet the total requirements of the participants. Certain provisions of the 1981 PCA allow the Agency, with appropriate notice, to make alternative arrangements to replace supplemental power purchases. Partial replacements of supplemental purchases have been made as discussed below. On August 6, 1996, the Board of Directors took action to notify CP&L of its intent to seek another supplemental power provider as of September 1, 2001. As a result of that notification, the Agency and CP&L finalized a new contract in 1998 for supplemental power purchases by the Agency from CP&L from 1999 to 2002, with an option for the Agency to extend the contract to 2003 and several options to procure power at market based rates thereafter. This new contract results in lower costs to the Agency for supplemental power over the term of the contract.

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 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 SEPA allocations. With the power generated from the initial project, together with supplemental purchases of power from CP&L and South Carolina Public Service Authority (Santee Cooper), 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.

- ***Santee Cooper***

The Agency had an agreement with Santee Cooper to purchase firm power from Santee Cooper through 1998. These purchases replaced supplemental purchases from CP&L. In connection with these purchases, the Agency negotiated a separate Power Coordination Agreement with CP&L to accommodate the provisions of the Santee Cooper agreement.

- *Peaking Project*

The Agency authorized the development of the peaking project, currently planned to consist of two electric generating plants, to provide peaking generation. The peaking project is intended to displace purchases by the Agency of supplemental capacity and energy from CP&L.

Sites for the two plants have been obtained near Battleboro, North Carolina and in Rocky Mount, North Carolina. The Rocky Mount site is anticipated to be connected with a substation owned and operated by the City of Rocky Mount, a 16.026% participant in the initial project and a 14.409% participant in the peaking project. The Agency board approved an agreement which specifies that the City of Rocky Mount will be responsible for the construction, at the Agency's expense, of an approximate 9 mile natural gas pipeline extension from a gas company's pipeline to the Rocky Mount site. The City of Rocky Mount will be responsible for all necessary permitting and obtaining land or land rights along the extension route. Following completion of construction, the City of Rocky Mount will own, operate, and maintain the pipeline extension.

The construction of the two approved generating plants is being financed by the Power System Revenue Bonds, Series 1993 A. These plants were scheduled to be placed into commercial operation by June 1998. In 1996, the Agency entered into an agreement with CP&L to delay the commercial operation of the peaking project 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.

Of the 32 Agency participants, 27 (representing 94.8% of Agency load), executed Peaking Project Power Sales Agreements. These peaking project participants with interests ranging from 0.0857% to 19.6651%, are liable for all costs associated with the construction and operation of the peaking project and have a proportionate right to the output of the project.

- *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 agreement 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 Developments*

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. These measures, together with increasing customer demand for lower-priced electricity and other energy services, have accelerated the industry's movement toward more competitive pricing structures. The Agency and its Board of Directors are addressing the Agency's position relative to deregulation. In addition, the Agency periodically reviews its regulatory assets and the impact of recovering such assets on Agency rates.

- *Study Commission on the Future of Electric Service in North Carolina*

In April 1997, the North Carolina legislature created the "Study Commission on the Future of Electric Service in North Carolina" (Study Commission). The Study Commission is comprised of 23 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 to examine 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. The Study Commission was originally charged with issuing a final report of the results of its study and its recommendations to the General Assembly of North Carolina in early 1999. However, current projections are that the Study Commission report will not be presented until 2000.

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 generally accepted accounting principles (GAAP). The Agency has adopted the principles promulgated by the Governmental Accounting Standards Board (GASB) and Financial Accounting Standard (FAS) 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 regulated assets even in a market environment.

- ***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, 1998, the remaining composite average life for Brunswick Units 1 and 2 was 11 years, Harris Unit 1 was 26 years, Roxboro Unit 4 was 16 years, and Mayo Unit 1 was 18 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 and with the peaking project, including interest expense net of investment earnings on funds not yet expended, 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. 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, including interest expense net of investment earnings on funds not yet expended, are capitalized until such time as the cores are placed in the reactor. At that time, 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 1998 and 1997 includes a provision of $3,364,000 and $3,359,000, 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 $687,000 and $676,000 in 1998 and 1997, 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 on January 31, 1998, the date 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. As of December 31, 1998, on-site spent nuclear fuel storage capability is sufficient for the full-core discharge of Brunswick Unit 1 through 1999, Brunswick Unit 2 through 2000, and Harris through 2002, assuming normal operating and refueling schedules. Provided that currently idle storage space at the Harris Plant can be activated by CP&L , 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. On December 23, 1998, CP&L submitted a license amendment application to the NRC requesting approval to activate and begin using the additional spent fuel storage at the Harris Plant.

- ***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 (NCMPA 1), 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 Governmental Accounting Standards Board Statement (GASB) No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools," which requires investments to be reported at fair value.

- ***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 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 the decommissioning cost of $105 million per unit (1986 dollars) set forth in the NRC regulations. 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.

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 $67,175,000 for Brunswick Unit 1, $66,995,000 for Brunswick Unit 2, and $63,287,000 for Harris.

- ***Fossil Fuel Inventory***

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

- ***Deferred Costs***

Deferred costs are shown net of accumulated amortization. Unamortized debt issuance costs at December 31, 1998 and 1997, shown net of accumulated amortization of $8,308,000 and $6,319,000, respectively, are being amortized on the interest method over the term of the related debt. Development costs, shown net of accumulated amortization of $5,014,000 and $4,744,000 at December 31, 1998 and 1997, 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, 1998 and 1997, shown net of accumulated amortization of $190,512,000 and $153,856,000, respectively, are deferred and are amortized over the term of the debt issued on refunding. Net costs to be recovered from future billings to participants are not amortized but will be recovered through future rates (see Note G).

- ***Discounts on Bonds***

Discounts on bonds (net of premiums) at December 31, 1998 and 1997 shown net of accumulated amortization of $10,660,000 and $8,950,000, 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 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.

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 1999 and 2000 will be approximately $17,776,000.

There were no interest costs capitalized as part of the cost of initial project capital additions under construction during 1998 and 1997.

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 follows. *See Table below.*

- ***Peaking Project***

Interest costs of $6,790,000 and $6,894,000 were capitalized as part of the cost of the peaking project in 1998 and 1997, respectively, net of

	Commercial Operation	*Maximum Net Dependable Capability*	*Agency* *Ultimate Ownership*	*Agency* *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	790	18.33	144.8
Harris Unit 1	1987	860	16.17	139.0
Total Nuclear-Fueled Capability				428.6
Total of All Units				639.7 MW

investment income on unexpended bond proceeds of $6,561,000 and $6,894,000, respectively.

- **Electric Plant in Service**

Original costs of major classes of the Agency's electric plant in service at December 31, 1998 and 1997 are as follows (in thousands of dollars). *See Table at upper right.*

	December 31, 1998	December 31, 1997
Land	$ 14,180	$ 14,193
Structures and improvements	480,018	480,560
Reactor plant equipment	373,878	374,940
Turbo generator units	119,791	120,631
Accessory electric equipment	175,280	175,575
Miscellaneous plant equipment	49,079	51,251
Other	27,641	27,598
Unclassified	170,058	170,097
	1,409,925	1,414,845
Accumulated depreciation	(533,776)	(493,377)
	$ 876,149	$ 921,468

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, 1998 and 1997 are as follows (in thousands of dollars). *See Table at lower right.*

	December 31, 1998	December 31, 1997
Land	$ 710	$ 710
Structures and improvements	1,492	1,492
Computer equipment	482	325
	2,684	2,527
Accumulated depreciation	(698)	(606)
	$1,986	$1,921

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 Option 2, a single financial institution collateral pool. Under Option 2, 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 Option 2. Because of the inability to measure the exact amount of collateral pledged for the Agency under Option 2, the potential exists for under-collateralization. However, the State Treasurer enforces strict standards for each Option 2 depository, which minimizes any risk of under-collateralization. At both December 31, 1998 and 1997, the Agency had $33,000, 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 following schedule (in thousands of dollars). *See Table below.*

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

E. 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, 1998 and 1997 is net of accumulated amortization of $6,609,000 and $6,220,000, respectively.

• INVESTMENTS ($000s)

	December 31,			
	1998		1997	
	Carrying Amount	*Market Value*	*Carrying Amount*	*Market Value*
Repurchase agreements	$215,582	$215,582	$200,896	$200,896
U.S. government securities	38,416	39,412	78,544	79,848
U.S. government agencies	268,537	273,092	267,589	273,074
Municipal bonds	37,227	23,281	22,672	23,845
Strips	18,431	21,523		
Collateralized mortgage obligations	119,357	135,473	131,585	132,614
	697,550	708,363	701,286	710,277
Decommissioning Trust securities	55,963	70,055	46,102	56,980
Operating cash	23	23	5	5
Restricted cash	10	10	28	28
Accrued interest	6,287	6,287	7,728	7,728
Total funds invested	$759,833	$784,738	$755,149	$775,018
Consisting of:				
Special funds invested		$515,065		$519,695
Decommissioning Trust		70,082		57,132
Operating assets		199,591		198,191
		$784,738		$775,018

• NET COSTS TO BE RECOVERED FROM FUTURE BILLINGS TO PARTICIPANTS

	Year Ended December 31, 1998	1997	*Inception to December 31,* 1998	1997
GAAP Items Not Included in Billings to Participants:				
• New project negotiation and Harris Plant litigation costs	$ 0	$ 0	$ 45,086	$ 45,086
• Increase in fair value of investments	(5,036)	(7,185)	(24,905)	(19,869)
• Depreciation	44,265	43,447	486,085	441,820
• Amortization	43,887	41,298	462,392	418,505
• Interest expense	189,208	196,413	3,074,320	2,885,112
	272,324	273,973	4,042,978	3,770,654
Bond Resolution Requirements Included in Billings to Participants:				
• Debt service	231,271	230,787	2,608,629	2,377,358
• Investment income not available for operating purposes	5,900	14,884	200,993	195,093
• Special funds deposits	24,362	12,946	200,782	176,420
• Special funds valuation	(22,331)	(22,268)	(237,669)	(215,338)
	239,202	236,349	2,772,735	2,533,533
• Net costs to be recovered from future billings to participants	$ 33,122	$ 37,624	$1,270,243	$1,237,121

F. NET COSTS TO BE RECOVERED FROM FUTURE BILLINGS TO PARTICIPANTS

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 the 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. 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 Financial Accounting Standard (FAS) No. 121 "Accounting for the Impairment of Long Lived Assets and for Assets to Be Disposed Of."

All rates must be approved by the board. Rates are designed on an annual basis and are reviewed quarterly. If determined to be inadequate, rates may be revised.

Net costs to be recovered from future billings to participants includes the following (in thousands of dollars). *See Table above.*

G. 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 initial project and the peaking project, and/or for other purposes as set forth in the resolution. Capital additions and future refundings may result in the issuance of additional bonds.

At December 31, 1997, the Agency had outstanding $3,390,396,000 of bonds. On

January 1, 1998, the Agency made principal payments of $41,150,000 for maturing bonds which included $551,000 in appreciated value on the Series 1988A Capital Appreciation serial bonds. In 1998, $250,000 of Series 1993 B bonds were retired. In addition, $932,000 was transferred from Accrued Interest on Bonds to Current Maturities of Bonds in order to reflect the amount due January 1, 1999 for the Series 1988 A and 1989 A Capital Appreciation serial bonds, bringing the total outstanding bonds at December 31, 1998 to $3,349,928,000. The various issues comprising debt outstanding is as follows (in thousands of dollars):

	December 31, 1998	1997
• **SERIES 1985G**		
5.75% maturing in 2016 with annual sinking fund requirements beginning in 2012	$ 95,565	$ 95,565
• **SERIES 1986A**		
5% maturing in 2017 with annual sinking fund requirements beginning in 2015	4,495	4,495
• **SERIES 1988A**		
7.3% to 7.6% capital appreciation serial bonds maturing annually from 1999 to 2002	2,842	3,304
6% maturing in 2026 with annual sinking fund requirements beginning in 2025	27,510	27,510
	30,352	30,814
• **SERIES 1988B**		
Variable rate, not to exceed 15%, Bond Interest Term Series maturing in 2010	5,000	5,000
Variable rate, not to exceed 15%, Bond Interest Term Series maturing in 2026 with annual sinking fund requirements beginning in 2023	150,000	150,000
	155,000	155,000
• **SERIES 1989A**		
7.2% to 7.4% capital appreciation serial bonds maturing annually from 1999 to 2003	6,959	6,670
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
7% maturing in 2017 with annual sinking fund requirements beginning in 2014	50,000	50,000
6.5% maturing in 2024	80,000	80,000
	215,849	215,560

	December 31, 1998	December 31, 1997
• **SERIES 1991A**		
5.9% to 6.1% maturing annually from 1999 to 2001	$ 6,270	$ 9,115
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	2,377	2,377
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
	330,022	332,867
• **SERIES 1993A**		
5.1% to 6.2% maturing annually from 1999 to 2013	53,340	55,585
6.4% maturing in 2021 with annual sinking fund requirements beginning in 2014	55,270	55,270
	108,610	110,855
• **SERIES 1993B**		
5.1% to 7.25% maturing annually from 1999 to 2009	405,880	410,185
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	55,800	55,800
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	33,485	33,485
	1,485,200	1,489,505
• **SERIES 1993C**		
4.625% to 7% maturing annually from 1999 to 2007	233,380	247,160
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
	311,935	325,715

	December 31, 1998	December 31, 1997
• **SERIES 1993D**		
5.875% maturing in 2013 with annual sinking fund requirements beginning in 2012	$ 29,305	$ 29,305
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
	80,000	80,000
• **SERIES 1995A**		
4.325% to 4.65% maturing annually from 1999 to 2001	48,205	57,015
5.125% maturing in 2012	14,090	14,090
	62,295	71,105
• **SERIES 1996A**		
5% to 5.2% maturing annually from 1999 to 2001	49,630	57,905
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
	302,125	310,400
• **SERIES 1996B**		
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 1997A**		
4.2% to 4.5% maturing annually from 1999 to 2001	2,420	2,455
5.375% maturing in 2024	29,185	29,185
	31,605	31,640
	3,349,928	3,390,396
Less: Current maturities of bonds	42,270	41,150
Unamortized discount	101,152	102,844
	$3,206,506	$3,246,402

The following is a summary of the debt service deposit requirements by project for bonds and Tax Exempt Commercial Paper outstanding at December 31, 1998 (in thousands of dollars). *See Tables at right.*

The tables reflect 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 $42,270,000 at December 31, 1998 were collected through rates during 1998 and deposited monthly into the Bond Fund to make the January 1, 1999 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 $3,664,375,000 and $3,657,608,000 at December 31, 1998 and 1997, respectively.

Certain proceeds of the Series 1985 G, 1986 A, 1988 A, 1989 A, 1991 A, 1993 B, 1993 C, 1995 A, 1996 A, and 1997 A bonds, along with the proceeds of the 1996 Tax-Exempt Commercial Paper, were used to establish trusts for refunding $4,140,685,000 of previously issued bonds. At December 31, 1998, $3,512,575,000 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

INITIAL PROJECT

Year	*Principal*	*Interest*	*Total*
• 1999	$ 58,923	$ 194,047	$ 252,970
• 2000	65,456	191,555	257,011
• 2001	58,747	190,930	249,677
• 2002	77,966	187,024	264,990
• 2003	81,237	179,806	261,043
• 2004	89,206	175,540	264,746
• 2005	97,403	170,562	267,965
• 2006	117,880	163,789	281,669
• 2007	127,105	156,099	283,204
• 2008	133,605	147,258	280,863
• 2009	118,230	139,061	257,291
• 2010	133,315	131,472	264,787
• 2011	140,711	123,541	264,252
• 2012	126,428	114,975	241,403
• 2013	144,484	107,550	252,034
• 2014	149,289	98,909	248,198
• 2015	150,825	90,259	241,084
• 2016	145,688	81,626	227,314
• 2017	144,855	73,060	217,915
• 2018	156,650	64,482	221,132
• 2019	168,735	55,687	224,422
• 2020	178,235	46,314	224,549
• 2021	170,830	36,610	207,440
• 2022	175,625	26,580	202,205
• 2023	171,325	16,954	188,279
• 2024	77,675	7,446	85,121
• 2025	77,970	3,805	81,775
Total	$3,338,398	$2,974,941	$6,313,339

PEAKING PROJECT			
Year	*Principal*	*Interest*	*Total*
• 1999	$ 2,470	$ 6,570	$ 9,040
• 2000	2,600	6,441	9,041
• 2001	2,740	6,301	9,041
• 2002	2,895	6,150	9,045
• 2003	3,055	5,987	9,042
• 2004	3,230	5,812	9,042
• 2005	3,425	5,618	9,043
• 2006	3,630	5,412	9,042
• 2007	3,855	5,190	9,045
• 2008	4,090	4,954	9,044
• 2009	4,335	4,709	9,044
• 2010	4,600	4,443	9,043
• 2011	4,880	4,161	9,041
• 2012	5,185	3,859	9,044
• 2013	5,505	3,537	9,042
• 2014	5,855	3,185	9,040
• 2015	6,235	2,810	9,045
• 2016	6,630	2,411	9,041
• 2017	7,055	1,987	9,042
• 2018	7,505	1,535	9,040
• 2019	7,985	1,055	9,040
• 2020	8,500	544	9,044
Total	$106,260	$92,671	$198,931

bonds and to redeem all refunded bonds at various dates prior to their original maturities, at par or a redemption price not to exceed 103%. 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 103½% of the respective principal amounts:

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

The Series 1988 B bonds initially bore interest for a short-term interest rate period consisting of consecutive and coincident Bond Interest Terms ranging from 1 to 270 days, during which each bond bore interest at a fixed rate. The bonds will continue to bear interest for a short-term interest rate period unless, at the option of the Agency, the bonds are adjusted to bear interest for a weekly interest rate period or a long-term interest rate period. At December 31, 1998, the weighted average interest rate was 3.892% with an average maturity of 100 days.

During a weekly interest rate period, the Series 1988 B bonds will be subject to tender for purchase on any business day at the option of the registered owners on seven days' notice. Each bond will be subject to mandatory tender for purchase upon adjustment to an alternative interest rate period, subject to the right of the registered owner to retain such bond in whole by appropriate written notice. The purchase of the bonds will be made first with the proceeds from the remarketing of such series and then with proceeds of drawings under a letter of credit sufficient to purchase all bonds of the series.

In connection with the Series 1988 B bonds, the Agency maintains a direct-pay letter of credit with a bank that is drawn upon to provide funds to pay principal of and interest on the Series 1988 B bonds when due, for which the Agency pays a fee of approximately $1,143,000 per year. Each draw upon the letter of credit is to be reimbursed from the proceeds of the Series 1988 B bonds remarketed on the same day the draw is made. In the event a draw is not so reimbursed, it becomes a borrowing which matures on the termination date of the letter of credit agreement (currently June 30, 1999). There were no borrowings under the letter of credit agreement at December 31, 1998.

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.

H. TAX-EXEMPT COMMERCIAL PAPER

The Agency authorized the issuance of tax-exempt commercial paper (TECP) to provide interim financing in an amount not to exceed $147,000,000. As of December 31, 1998 and 1997, the Agency had $137,000,000 outstanding which approximates fair market value. The TECP has an average maturity of 117 days and an average interest cost of approximately 3.938%. The Agency maintains a direct-pay letter of credit with a bank for $141,500,000 that is drawn upon to provide funds to pay principal of and interest on the TECP when due, for which the Agency pays a fee of approximately $708,000 per year. Each draw upon the letter of credit is to be reimbursed from the proceeds of TECP issued on the same day the draw is made. In the event a draw is not so reimbursed, it becomes a borrowing which matures on the termination date of the letter of credit agreement (currently November 24, 1999). There were no borrowings under the letter of credit agreement at December 31, 1998.

I. LETTER OF CREDIT

At December 31, 1998, the Agency had a $12,900,000 unused letter of credit from a bank payable to CP&L. The letter of credit is required to be maintained, in compliance with the agreements between CP&L and the Agency. The Agency is required under the terms of the letter of credit agreement to pay quarterly commitment fees, such fees being a percentage of the unused letter of credit (approximately $72,000 annually).

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, 2001, 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, 1998 and 1997, the Agency paid ElectriCities $4,174,000 and $4,696,000, respectively, of which $1,000 and $1,000, respectively, have been capitalized as development costs.

K. CONTINGINCIES

The Price-Anderson Act limits the public liability for a nuclear incident at a nuclear generating unit to $9,800,000,000, 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 $88,000,000 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.

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 deductibles of $500,000 to $1,000,000. In addition, nuclear liability insurance exists in the form and amount necessary to meet the financial requirements established by the NRC.

REQUIRED SUPPLEMENTAL INFORMATION — YEAR 2000 ISSUE (unaudited)

Management is aware of the potentially significant implications of the Year 2000 issue for the Agency. The concerns are assuring the continued operations of the jointly owned generation facilities, maintaining the supply of electric power to their participants, and fulfilling obligations under the bond resolution. Management's plan focuses on three main areas:

1. *The preparedness of key suppliers (CP&L generation and transmission facilities, VEPCO transmission),*
2. *The continued functionality of the participants' distribution systems, and*
3. *The internal operations of the administrative offices of ElectriCities.*

The Agency maintains contact with its suppliers and participants to stay abreast of where they stand regarding Y2K remediation.

ElectriCities completed its assessment and remediation of in-house corporate business systems in December 1996, and has been working to complete preparation of all non-business computer systems by April 1999. Testing of all computer systems under the control of the Management Information Services Department (MIS) has been completed and is approximately 75% complete for the other areas that fall outside of MIS. However, completion of these remediation efforts does not guarantee that these systems will be Y2K compliant.

Management is committed to expend whatever it takes to address this issue. Thus far, the majority of the work has been performed by internal staff. Costs for external resources have been minimal. The pilot project and external expenses are expected to total approximately $200,000 for the life of the project. However, Management will continue to review budget needs and will not limit efforts due to external costs.

SCHEDULE OF CHANGES IN Assets OF FUNDS INVESTED ($000s)

	Funds Invested Jan. 1, 1997	Bond Proceeds	Power Billing Receipts	Investment Income	Disbursments	Transfers
Construction Fund:						
Initial project construction account	$ 30,956	$ 0	$ 0	$ 1,812	$ (6,655)	$ 361
Peaking construction account	98,056			6,504	(10)	(1,054)
	129,012			8,316	(6,665)	(693)
Bond Fund:						
Interest account	83,046	(909)		2,416	(177,041)	182,564
Reserve account	213,474	(792)		15,028		(15,808)
Principal account	20,289			1,032	(21,746)	39,805
Peaking interest account	3,450			5	(6,849)	6,795
Peaking principal account	2,146			1	(2,145)	2,244
Peaking reserve account	6,988			459		(394)
	329,393	(1,701)		18,941	(207,781)	215,206
Reserve & Contingency Fund:						
Initial project account	22,597	(79)		2,559	(1,239)	(1,586)
Peaking account	705			37		(37)
	23,302	(79)		2,596	(1,239)	(1,623)
Decommissioning Fund	2,956			224		
Special Reserve Fund	1,023			77		(73)
Revenue Fund:						
Revenue account	22,222		308,206	724	(16,059)	(287,604)
Peaking account						
Rate stabilization account – CP&L	61,997	(4,301)		3,478		(11,315)
Rate stabilization account – VEPCO	9,007	(536)		631		1,315
	93,226	(4,837)	308,206	4,833	(16,059)	(297,604)
Operating Fund:						
Working capital account	31,804			2,413	(109,894)	104,114
Fuel account	24,304					(1,651)
	56,108			2,413	(109,894)	102,463
Supplemental Fund:						
Supplemental account	33,530		100,160	1,906	(85,257)	(17,676)
CP&L rate stabilization	24,505			1,679		
	58,035		100,160	3,585	(85,257)	(17,676)
	$693,055	$(6,617)	$408,366	$40,985	$(426,895)	$ 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, 1998 and 1997, respectively. See accompanying Independent Auditors' Report.

SCHEDULE OF CHANGES IN Assets OF FUNDS INVESTED ($000s)

Funds Invested Dec. 31, 1997	Power Billing Receipts	Investment Income	Disbursements	Transfers	Funds Invested Dec. 31, 1998
$ 26,474	$ 0	$ 1,455	$ (7,817)	$ (769)	$ 19,343
103,496		6,561		(6,625)	103,432
129,970		8,016	(7,817)	(7,394)	122,775
90,076		2,187	(182,685)	179,676	89,254
211,902		15,011		(13,946)	212,967
39,380		1,014	(39,196)	38,907	40,105
3,401		6	(6,745)	6,685	3,347
2,246		1	(2,245)	2,349	2,351
7,053		434		(456)	7,031
354,058		18,653	(230,871)	213,215	355,055
22,252		2,641	(773)	(1,833)	22,287
705		35		(37)	703
22,957		2,676	(773)	(1,870)	22,990
3,180		242			3,422
1,027		67		(52)	1,042
27,489	300,627	589	(16,212)	(275,541)	36,952
	7,089	145		(5,166)	2,068
49,859		3,142		(84)	52,917
10,417		742		(454)	10,705
87,765	307,716	4,618	(16,212)	(281,245)	102,642
28,437		2,025	(113,169)	106,552	23,845
22,653				(9,250)	13,403
51,090		2,025	(113,169)	97,302	37,248
32,663	109,461	1,925	(93,207)	(19,956)	30,886
26,184		1,600			27,784
58,847	109,461	3,525	(93,207)	(19,956)	58,670
$708,894	$417,177	$39,822	$(462,049)	$ 0	$703,844

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, 1998 and 1997, respectively.
See accompanying Independent Auditors' Report.

SCHEDULE OF Revenues AND EXPENSES

PER BOND RESOLUTION AND OTHER AGREEMENTS ($000s)

	Year Ended December 31, 1998				*Year Ended December 31, 1997*		
	Peaking Project	*Initial Project*	*Supplemental*	*Total*	*Initial Project*	*Supplemental*	*Total*
REVENUES:							
Sales of electricity to participants	$ 9,247	$305,376	$ 99,839	$414,462	$299,714	$108,886	$408,600
Sales of electricity to utilities		34,457	570	35,027	36,265	1,877	38,142
Rate stabilization fund withdrawal		537		537	10,002		10,002
Special funds valuations		22,330		22,330	22,268		22,268
Investment revenue available for operations	4,476	21,588	(656)	25,408	24,536	2,007	26,543
	13,723	384,288	99,753	497,764	392,785	112,770	505,555
EXPENSES:							
Operation and maintenance		39,108	5	39,113	42,655	5	42,660
Fuel		37,340		37,340	38,194		38,194
Power coordination services:							
Purchased power	8,950	8,252	77,687	94,889	7,623	89,057	96,680
Transmission & distribution			17,677	17,677		16,976	16,976
Other	(1)		86	85		93	93
	8,949	8,252	95,450	112,651	7,623	106,126	113,749
Administrative & general-CP&L		19,724		19,724	22,701		22,701
Administrative & general-Agency	(2)	2,607	3,706	6,311	2,499	3,081	5,580
Amounts in lieu of taxes		3,925		3,925	4,352		4,352
Gross receipts tax	298	9,795	3,141	13,234	9,613	3,441	13,054
Letters of credit commitment fees		1,907		1,907			
Debt service	2,350	234,579	127	237,056	236,682	117	236,799
Special funds deposits:							
Revenue fund	2,128			2,128			
Reserve & contingency fund		22,771		22,771	22,948		22,948
Decommissioning fund		4,280		4,280	3,839		3,839
	2,128	27,051		29,179	26,787		26,787
	13,723	384,288	102,429	500,440	392,785	112,770	505,555
Excess (Deficiency) of Revenues Over Expenses	$ 0	$ 0	$ (2,676)	$ (2,676)	$ 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, 1998 and 1997, respectively.

See accompanying Independent Auditors' Report.

NCEMPA STATISTICAL Highlights

TEN YEARS AT A GLANCE

	1998	1997	1996	1995	1994
• Megawatt-hour Sales (MWH)	6,556,169	6,273,385	6,291,401	6,142,495	5,810,477
• Peak Billing Demand (kW)	1,190,030	1,185,129	1,116,786	1,194,209	1,135,450
• Operating Revenues	$449,489,000	$446,742,000	$460,674,000	$462,664,000	$458,023,000
• (Deficiency) Excess of Revenues over Expenditures	($2,676,000)	$0	$0	$0	$0
• Sales to CP&L (Revenues)	$35,027,000	$38,142,000	$38,416,000	$40,901,000	$61,302,000*
• Average Monthly Power Purchases by Cities (MWh)	546,347	522,782	524,283	511,874	484,206
• Average Monthly Billings by Cities	$34,539,000	$34,050,000	$35,188,000	$35,147,000	$33,060,000

	1993	1992	1991	1990	1989
• Megawatt-hour Sales (000)	5,865,354	5,509,338	5,466,779	5,247,861	5,249,890
• Peak Billing Demand (kW)	1,155,200	1,112,185	1,108,182	1,083,532	1,039,500
• Operating Revenues	$444,271,000	$398,585,000	$398,000,000	$370,806,000	$357,893,000
• Excess (Deficiency) of Revenues over Expenditures	$20,830,000	$2,000	$0	$(3,462,000)	$(18,701,000)
• Sales to CP&L (Revenues)	$53,609,000*	$39,987,000	$46,139,000	$47,569,000	$53,996,000
• Average Monthly Power Purchases by Cities (MWh)	488,780	459,112	455,565	437,322	441,241
• Average Monthly Billings by Cities	$32,555,000	$29,883,000	$29,322,000	$26,936,000	$25,325,000

** 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

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ARTHUR ANDERSEN LLP

North Carolina Electric Membership Corporation

Financial Statements as of December 31, 1998, 1997 and 1996
Together with Report of Independent Public Accountants

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, 1998 and 1997, and the related statements of operations and members' equity and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards and the Standards for financial audits contained in *Government Auditing Standards* (1994 revision) 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, 1998 and 1997, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

In accordance with *Government Auditing Standards*, we have also issued a report dated March 5, 1999, 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.

Arthur Andersen LLP

Raleigh, North Carolina,
March 5, 1999.

North Carolina Electric Membership Corporation

Balance Sheets — December 31, 1998 and 1997

(in thousands)

Assets	1998	1997
Electric plant:		
In-service	$1,428,081	$1,424,772
Accumulated depreciation	(547,649)	(512,239)
	880,432	912,533
Nuclear fuel, at amortized cost	33,080	24,703
Construction work in process	6,402	13,140
	919,914	950,376
Other assets and investments:		
Long-term investments	124,350	82,662
Noncurrent receivables	24,270	20,044
Investments in associated organizations	1,537	7,480
Special deposits	38,685	36,196
Decommissioning fund	47,983	61,408
Deferred revenue fund	6,234	25,596
	243,059	233,386
Current assets:		
Cash and cash equivalents	18,499	20,505
Short-term investments	16,865	71,491
Accounts receivable	91,487	99,963
Interest receivable	1,230	3,959
Other current assets	66	158
	128,147	196,076
Deferred charges:		
Regulatory asset	59,467	63,325
Deferred loss on debt extinguishment (Note 6)	20,511	0
Debt issuance costs	9,327	9,798
Preliminary project costs	9,421	9,421
Other	2,199	1,571
	100,925	84,115
	$1,392,045	$1,463,953

Equities and Liabilities	1998	1997
Equities:		
Membership fees	$ 1	$ 1
Patronage capital	22,112	22,112
Unrealized gain on available for-sale securities	455	694
	22,568	22,807
Long-term debt	1,111,360	1,130,935
Current liabilities:		
Current maturities of long-term debt	28,985	27,454
Accounts payable	35,784	37,231
Accrued interest	1,107	1,178
Other accrued expenses	11,377	11,614
	77,253	77,477
Deferred credits and other liabilities:		
Accumulated deferred federal income taxes (Note 1)	110,453	110,453
Reserve for decommissioning	47,983	61,408
Accrued Department of Energy assessment	5,593	6,067
Deferred revenues	6,234	25,596
Regulatory liability	8,579	27,390
Other noncurrent liabilities	2,022	1,820
	180,864	232,734
Commitments and contingencies (Notes 7, 8, 9, 10 and 11)		
	$1,392,045	$1,463,953

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, 1998, 1997 and 1996
(in thousands)

	1998	1997	1996
Operating revenues	$644,619	$629,700	$650,167
Operating expenses:			
Fuel and purchased power	392,751	380,980	404,451
Other production expenses	106,068	106,934	104,763
Depreciation and amortization	44,739	44,602	45,806
Administrative and general	20,518	14,378	12,257
General taxes	12,097	12,338	11,172
Federal income taxes	0	(2,374)	0
	576,173	556,858	578,449
Operating margin	68,446	72,842	71,718
Other income (expense):			
Interest income	11,521	17,775	20,897
Other	3,110	(106)	(173)
	14,631	17,669	20,724
Interest charges:			
Interest expense	81,606	89,539	91,446
Debt fees and expenses	1,471	972	996
	83,077	90,511	92,442
Net margin	0	0	0
Unrealized (losses) gains on available-for-sale securities	(239)	3,095	(5,351)
Comprehensive income	(239)	3,095	(5,351)
Members' equity, beginning of year	22,807	19,712	25,063
Members' equity, end of year	$ 22,568	$ 22,807	$ 19,712

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, 1998, 1997 and 1996
(in thousands)

	1998	1997	1996
Cash flows from operating activities:			
Net margin	$ 0	$ 0	$ 0
Adjustments to reconcile net margin to net cash and cash equivalents (used in) provided by operating activities-			
Depreciation and amortization	46,387	45,695	46,858
Provision for deferred income taxes	0	(2,374)	0
Amortization of nuclear fuel	14,895	16,259	17,374
Amortization of regulatory liability	(39,718)	(33,634)	(11,976)
Amortization of deferred revenues	(19,362)	(31,447)	(11,198)
Interest on decommissioning fund	2,929	4,845	3,245
Deferred charges	(21,784)	(3,473)	(625)
Other noncurrent assets and liabilities	(4,024)	(2,849)	1,030
Changes in other operating assets and liabilities:			
Accounts receivable	8,476	4,811	(55,525)
Interest receivable	2,729	201	3,054
Accounts payable	(1,447)	7,327	(14,213)
Accrued interest	(71)	78	(21,628)
Other	(5)	1,551	31
Net cash and cash equivalents (used in) provided by operating activities	(10,995)	6,990	(43,573)
Cash flows from investing activities:			
Additions to electric plant	(21,329)	(28,842)	(38,139)
Decrease (increase) in decommissioning fund	13,425	(9,845)	61,469
Decrease (increase) in long-term investments	(41,930)	84,549	(38,416)
Decrease in deferred revenue fund	19,362	31,447	11,198
Decrease (increase) in short-term investments	54,629	(55,141)	28,639
Other, net	2,876	(4,147)	(3,359)
Net cash and cash equivalents provided by investing activities	27,033	18,021	21,392
Cash flows from financing activities:			
Principal payments of long-term debt	(36,287)	(25,304)	(28,491)
Extinguishment of long-term debt	(253,148)	0	0
Proceeds from issuance of long-term debt	271,391	0	0
Net cash and cash equivalents used in financing activities	(18,044)	(25,304)	(28,491)
Net decrease in cash and cash equivalents	(2,006)	(293)	(50,672)
Cash and cash equivalents, beginning of year	20,505	20,798	71,470
Cash and cash equivalents, end of year	$ 18,499	$20,505	$ 20,798

	1998	1997	1996
Supplemental disclosure of cash flow information - Cash paid during the year for:			
Interest	$ 81,472	$89,363	$112,679
Income taxes	146	0	1,900

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

North Carolina Electric Membership Corporation

Notes to Financial Statements
December 31, 1998, 1997 and 1996

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 the full-requirements supplier, providing power generation, wholesale electric service and transmission, to its members who in turn service more than 700,000 homes, farms and businesses in North Carolina. The Company follows generally accepted accounting principles 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 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
Automobiles	4 years

The depreciation rate for the Catawba Nuclear Station includes a provision to provide for the expected cost of decommissioning the nuclear facility. In compliance with a Nuclear Regulatory Commission (NRC) regulation, amounts recovered through rates for estimated decommissioning costs (plus interest thereon) are maintained in separate investment accounts, including an external trust fund. The provision for expected decommissioning costs is charged to operations with an offsetting credit to the reserve for decommissioning. Investment earnings generated from the external trust fund and internal funds 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 and the corresponding decommissioning provision included in the depreciation rate are adjusted periodically to reflect changing price levels and technology. Based on a 1994 site study of expected decommissioning costs, including the costs of decontamination, dismantling and site restoration, the Company's portion of such costs is estimated to aggregate $658,300,000. The estimate assumes a future annual escalation rate of 4.5% in decommissioning costs. 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. As a result, the internal decommissioning fund was eliminated. The regulatory liability will be amortized through the year 2000 based on each member's KW and KWH billing determinants for the applicable year. Total amortization of the regulatory liability was $39,718,000 in 1998, $33,634,000 in 1997 and $11,976,000 in 1996.

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 imposes a stricter criterion for regulatory assets by requiring that such 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.

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 $14,895,000 in 1998, $16,259,000 in 1997 and $17,374,000 in 1996. 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.

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 will be utilized to reduce member revenue requirements in 1996 through 2000 as authorized by the Board of Directors. The deferred revenues are allocated to members based on their KW and KWH billing determinants for the applicable year. The cash equivalent of all deferred revenues is segregated into the deferred revenue fund and will remain in such fund until it is used to reduce member revenue requirements. In 1996, the Company commenced amortization of this deferred revenue which reduced member revenue requirements. Deferred revenue amortization reduced member revenue requirements by $19,362,000 in 1998, $31,447,000 in 1997 and $11,198,000 in 1996.

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 subject to 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, as amended (the Code). In 1985, the Company reported as a taxable entity as a result of income received from Duke Power Company under a capacity and energy sell-back agreement applicable to Catawba Units No. 1 and 2. As a taxable electric cooperative, the Company has annually allocated its income and deductions between member and nonmember activities. Any member taxable income has been offset with a patronage exclusion.

A detail of the provision for federal income taxes in 1998, 1997 and 1996 is shown as follows (in thousands):

	1998	1997	1996
Current	$0	$ 0	$0
Deferred	0	(2,374)	0
Income taxes charged to operations	$0	$(2,374)	$0

The difference between the statutory federal income tax rate on net margin before income taxes and the Company' s effective income tax rate is the result of losses from member operations which cannot be used to offset nonmember income.

As discussed further in Note 9, in 1994 the Company reduced accumulated deferred federal income taxes by $30,505,000 which reflects the tax effect of the write-off of the noncurrent receivable from Duke Power Company (Duke). The tax benefit was used to reduce the regulatory asset established in conjunction with this transaction.

Pursuant to a court decision, the Company has retroactively adjusted the allocation of interest income between member and nonmember sources. As a result, accumulated deferred federal income taxes were reduced by $19,198,000 with a corresponding decrease in the noncurrent receivable from members in 1996.

In 1998, the Company did not record a charge to current or deferred income tax expense. In 1997, the Company recorded a reduction of deferred federal income taxes of $2,374,000 resulting from a revision of its deferred tax liabilities. In 1996, there was no charge to current or deferred income tax expense.

The components of the net deferred tax liabilities as of December 31, 1998 and 1997, were as follows (in thousands):

	1998	1997
Deferred tax assets-		
Net operating losses	$ 73,203	$ 74,668
Member loss carryforwards	77,121	68,918
General business credits	101,893	101,808
Alternative minimum tax credit	9,230	9,230
Deferred revenue	2,182	8,959
Nuclear decommissioning	15,717	14,553
Other	7,946	6,355
	287,292	284,491
Less - Valuation allowance	(101,893)	(101,808)
	185,399	182,683
Deferred tax liabilities-		
Depreciation	(278,447)	(274,574)
Regulatory asset	(15,285)	(16,276)
Department of Energy assessment	(1,958)	(2,124)
Other	(162)	(162)
	(295,852)	(293,136)
Net accumulated deferred federal income tax	$(110,453)	$(110,453)

The Company has federal tax net operating loss carryforwards (NOLs) and unused general business credits (consisting primarily of investment tax credits) as follows (in thousands):

Expiration Date	Tax Credits	NOLs
2000	$ 47,078	$ 0
2001	53,355	0
2002	716	0
2003	333	0
2004	18	70,343
2005	28	0
2006	35	0
2007	38	0
2008	44	0
2009	46	36,620
2010	25	0
2011	27	8,295
2012	65	0
2013	85	0
	$101,893	$115,258

Based on the Company's historical taxable transactions and the timing of the reversal of existing temporary differences, management believes it is more likely than not that future taxable income will be sufficient to realize the benefit of the NOLs existing at December 31, 1998, before their respective expiration dates. However, as reflected in the above valuation allowance, management does not believe it is more likely than not that the tax credits will be utilized before expiration.

Deferred Charges

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

	Estimated Periods
Regulatory asset (Note 9)	20 years
Deferred loss on debt extinguishment (Note 6)	17 years
Debt issuance costs	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 generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

New Accounting Pronouncements

Effective January 1, 1997, the Company adopted the provisions of SFAS No. 125, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and Statement of Position 96-1, "Environmental Remediation Liabilities." The adoption of these statements did not have a material impact on the financial position or result of operations of the Company.

Effective January 1, 1998, the Company adopted the provisions of SFAS No. 130, "Reporting Comprehensive Income." The statement of operations and members' equity has been modified accordingly to meet the disclosure and presentation requirements of this statement.

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 $1,350,073,000 in 1998 and $1,347,300,000 in 1997, 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 in the Carolina Power & Light Company (CP&L) and Virginia Electric and Power Company (VEPCO) service areas, 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, 1998 and 1997, is as follows (in thousands):

	1998		1997	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 18,499	$ 18,499	$ 20,505	$ 20,505
Short-term investments	16,865	16,865	71,491	71,491
Long-term investments	124,350	124,350	82,662	82,662
Special deposits	38,685	38,685	36,196	36,196
Decommissioning fund	47,983	54,041	61,408	62,938
Deferred revenue fund	6,234	6,234	25,596	25,596
Long-term debt	1,140,345	1,140,345	1,158,389	1,158,389

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 and the deferred revenue fund is determined based on the requirements of the related obligation. The special deposits fund balance is contractually determined to meet certain funding requirements. Unrealized gains or losses associated with the fair value of available-for-sale investments are transferred to the appropriate long-term or short-term investment accounts in order to maintain a fixed fund balance. The fair value of the Company's long-term debt is estimated based on the current rates offered to the Company for debt of similar maturities.

In 1994, the Company adopted SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The Company's investments are 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, 1998 and 1997, $47,983,000, and $61,408,000 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, 1998 and 1997, were as follows (in thousands):

December 31	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Estimated Fair Value
1998-				
Available-for-sale securities:				
U.S. Government and agency securities	$ 41,198	$2,569	$ (127)	$ 43,640
Corporate bonds	27,019	131	(16)	27,134
Equity investments	75,566	5,772	(8,883)	72,455
Other	60,395	1,015	(6)	61,404
	$204,178	$9,487	$(9,032)	$204,633
Held-to-maturity securities:				
U.S. Government and agency securities	$ 13,771	$ 0	$ (174)	$ 13,597
Equity investments	19,853	6,618	(703)	25,768
Demand notes	10,899	321	(4)	11,216
Other	3,460	0	0	3,460
	$ 47,983	$6,939	$ (881)	$ 54,041
1997-				
Available-for-sale securities:				
U.S. Government and agency securities	$219,535	$1,160	$ (462)	$220,233
Other	16,221	0	(4)	16,217
	$235,756	$1,160	$ (466)	$236,450
Held-to-maturity securities:				
U.S. Government and agency securities	$ 25,549	$ 201	$ (708)	$ 25,042
Equity investments	10,464	2,020	(48)	12,436
Demand notes	22,404	0	0	22,404
Other	2,991	65	0	3,056
	$ 61,408	$2,286	$ (756)	$ 62,938

Proceeds from the sale of marketable securities were $368,115,000 and $134,968,000 in 1998 and 1997, respectively. Related net realized gains and (losses) included in income were $2,830,000 and $(375,000) in 1998 and 1997, respectively.

4. Investments in Associated Organizations:

Investments in associated organizations are stated at cost at December 31, 1998 and 1997, and were as follows (in thousands):

	1998	1997
National Rural Utilities Cooperative Finance Corporation-		
Subordinated Term Certificate	$ 0	$7,040
Capital Term Certificates	320	321
Patronage Capital Certificates	115	118
Other	1	1
Other investments	1,101	0
	$1,537	$7,480

The Capital Term Certificates bear interest at 3% to 5% per annum. These certificates are required to be maintained under the note agreement 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. NRUCFC redeemed the Subordinated Term Certificate in December 1998. These investments in associated organizations are similar to compensating bank balances and are necessary in order to maintain current financing arrangements. Accordingly, carrying value approximates fair value as there is no market for these investments.

5. Special Deposits:

Special deposits consist of bond and debt service reserve funds for pollution control bonds as required by the Company's bond agreements and special reserve funds required by the Company's agreements with Duke. Bond funds serve as payment clearing accounts and the debt service reserve funds maintain amounts equal to the maximum annual debt service of each bond issue. Bond and debt service reserve funds totaled $17,674,000 and $16,597,000 at December 31, 1998 and 1997, 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 12-month period ended December 31, 1998. The depository account totaled $21,011,000 as of December 31, 1998, and $19,599,000 as of December 31, 1997.

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):

	1998	1997
FFB mortgage and RUS note advances, maturing at various dates through 2018, interest rates varying from 5.00% to 5.61% (average year-end rates of 5.61% for 1998 and 8.07% for 1997)	$1,028,043	$1,042,978
Pollution Control Revenue Bonds, maturing in 2014 with annual sinking fund requirements guaranteed by NRUCFC-Weekly series, interest payable monthly at varying rates (4.05% at December 31, 1998, and 3.89% at December 31, 1997)	21,950	22,550
Semiannual series, interest payable semiannually at varying rates (3.30% at December 31, 1998, and 3.70% at December 31, 1997)	89,650	92,150
NRUCFC note advances, interest and principal payable quarterly through June 14, 2023, interest rate 8% at December 31, 1998 and 1997	702	711
	1,140,345	1,158,389
Less - Current maturities	(28,985)	(27,454)
	$1,111,360	$1,130,935

In July 1998, the Company refinanced substantially all FFB notes with an outstanding principal balance of $1,015,104,000. The interest rates on these notes were reduced from existing rates, ranging from 7.69% to 10.52%, to a fixed rate of 5.61%. This rate will remain in effect for a 10-year period ending in 2008, at which time the Company has the option to reprice the outstanding principal for the remaining term. In conjunction with the refinancing the Company paid a penalty of $2,861,000 and financed an additional premium of $114,435,000 over the term of the original debt. In accordance with SFAS No. 125, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," and EITF Issue 96-19, "Debtor's Accounting for a Modification or Exchange of Debt Instruments," the Company individually assessed the refinanced notes to determine whether each transaction should be accounted for as an extinguishment. As a result, $253,148,000 in debt was extinguished and replaced by $271,391,000 in new debt, representing the fair value of the related notes. In addition, the Company wrote off $695,000 and $2,375,000 of related refinancing penalties and original debt issuance costs, respectively. The resulting loss on extinguishment of $21,313,000 was recorded as a deferred charge to be amortized over a 17-year period (the remaining life of the debt) in accordance with the recovery period established by the Board of Directors. Likewise, the remaining unrecorded premium of $96,192,000 will be recognized as interest expense over the same 17-year period. This transaction will result in a net economic gain of approximately $68,647,000 over the remaining term of the notes.

Maturities of the long-term debt described above for the five-year period from January 1, 1999, and thereafter, are summarized below (in thousands):

Years	Amount
1999	$ 28,985
2000	39,418
2001	51,509
2002	44,839
2003	47,314
Thereafter	928,280
	$1,140,345

The Company also has a $30 million line of credit with NRUCFC which was unused at December 31, 1998. 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 amounts accrued for pension expense, except during a period when a moratorium is in effect. A moratorium on contributions was lifted in October 1996 at which time contributions to the Program continued. Payments to the Program for current period service cost were $901,000 in 1998, $453,000 in 1997 and $225,000 in 1996.

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, following the date on which they complete one year of service. 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 $249,000 in 1998, $237,000 in 1997 and $230,000 in 1996.

8. Other Postemployment and Postretirement Benefits:

As of January 1, 1995, the Company adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." This accounting standard requires postretirement benefits to be recognized as earned by employees, rather than as paid. Prior to 1995, the cost of these benefits was recognized as an expense when premiums were paid.

The Company elected to adopt this standard on an immediate recognition basis. As a result, the accumulated postretirement benefit obligation at January 1, 1995, of $870,000 was recognized as a cumulative effect of change in accounting principle. The obligation has not been funded.

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):

	1998	1997
Retired plan participants	$ 262	$ 128
Active plan participants	1,194	941
Unrecognized actuarial gain	220	431
Accumulated postretirement benefit obligation	$1,676	$1,500

Net postretirement benefit cost for 1998 and 1997 is included in administrative and general expenses and consists of the following components (in thousands):

	1998	1997
Service cost - Benefits attributed to service during the period	$116	$103
Interest cost on accumulated postretirement benefit obligation	87	63
Amortization of actuarial gain	(6)	(23)
Net postretirement benefit cost	$197	$143

The Company has revised certain assumptions related to the computation of the accumulated postretirement benefit obligation, resulting in a net gain of $226,000 which will be deferred and amortized over 16 years under the provisions of SFAS No. 106. The current year amortization of $6,000 is included as a component of net postretirement benefit cost. For measurement purposes, an 8.0% annual increase in the cost of covered health care benefits was assumed for 1998; the rate was assumed to decrease gradually to 5.0% in the year 2004 and remain at that level thereafter. Increasing the assumed health care cost trend by one percentage point in each year would increase the accumulated postretirement benefit obligation for 1998 by $266,000. The average discount rate used in determining the accumulated postretirement benefit obligation was 7%.

In November 1992, the Financial Accounting Standards Board (FASB) issued SFAS No. 112, "Employers' Accounting for Postemployment Benefits." The statement requires the accrual of the expected cost of such benefits (primarily disability benefits) during the employees' years of service. The statement, adopted by the Company in 1994, resulted in a postemployment benefit obligation of $346,000 at December 31, 1998. The annual incremental charge and the revision of actuarial assumptions did not have a material impact on the Company's financial condition or results of operations.

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 is being amortized over a 20-year period in accordance with the recovery period established by the Board of Directors.

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, 1998, of $5,593,000 is included in the accompanying balance sheets in deferred credits and other liabilities.

Power Coordination Agreements and Purchased Power Commitments

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 1998, the Company negotiated a Power Supply Agreement (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 a single noncoincident peak rate which is essentially revenue-neutral. These new agreements are effective January 1, 1999.

In 1996, the Company began receiving 200 MW of capacity from American Electric Power (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

In 1994, the Company entered into an agreement with Black & Veatch Construction, Inc. and H. B. Zachry to build a 330 MW plus 120 MW of reserves 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 incurred preliminary project costs of $9,421,000 through December 31, 1998, which are included in deferred charges in the accompanying balance sheets.

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 $8.9 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 $79.3 million (NCEMC's share is $22.3 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 Mutual Limited (NML) which provides $500 million in primary property damage coverage for each of Duke's nuclear facilities. If NML's losses ever exceed its reserves, Duke will be liable, on a pro rata basis, for additional assessments of up to $34 million (NCEMC's share is $9.6 million). This amount represents five times Duke's annual premium to NML. 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 NML policies applicable to Catawba.

Duke is also a member of Nuclear Electric Insurance Limited (NEIL) and 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 $40 million (NCEMC's share is $11.3 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 $3.5 million per week, after a 21-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 104 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 $27 million (NCEMC's share is $7.6 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. (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 nominal fee for office space and use of the Company's copy machines.

Charges to NCAEC for staff services were $2,235,000 in 1998 and $1,058,000 in 1997. Charges to TEMA for these services were $1,294,000 in 1998 and $992,000 in 1997. Charges to the CECSIF were $37,000 in 1998 and $23,000 in 1997.

Prior to 1998, the Company made a separate charge to its related parties for leased office space and computer equipment. Charges for rent were $54,000 and $21,000 to NCAEC and TEMA, respectively, in 1997.

The Company has accounts receivable net of accounts payable with related parties at December 31, 1998 and 1997, as follows (in thousands):

	1998	1997
NCAEC	$431	$274
TEMA	232	275
TSE Services, Inc.	60	0
ElecTel Cooperative Credit Union	0	1
CECSIF	8	0
	$731	$550

The Company has designated $27,000,000 for loans to members related to economic development and additional funds for the construction of customer owned generation. At December 31, 1998 and 1997, outstanding loans totaling $10,232,000 and $5,477,000, respectively, have been included in accounts receivable and noncurrent receivables in the accompanying balance sheets. Economic development loans 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 accrue interest at fixed and variable rates ranging from 5.0% to 8.3%. The repayment terms for these loans range from 3 to 7 years.

12. Subsequent Events:

In 1999 the Company expects to file as an exempt organization under Section 501 (c)(12) of the Code. The impact of this event will be accounted for in 1999. Management expects the accounting for this event to result in the elimination of the accumulated deferred federal income tax liability as well as certain related assets.