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Policy Options for North Carolina's Municipal Power Agencies

Final Report
Volume 1—Task 4: Analysis of Options for Resolving Stranded Cost Issues

Prepared for

Legislative Study Commission on the Future of Electric Service in North Carolina
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Center for Economics Research
Research Triangle Park, NC 27709

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Executive Summary

The evolution of North Carolina's two municipal power agencies (MPAs), the North Carolina Eastern Municipal Power Agency (NCEMPA) and the North Carolina Municipal Power Agency 1 (NCMPA1) is attributable to institutions and forces that took shape nearly a century ago. In the late 1800s and the early part of this century, North Carolina municipalities built their own power supply systems. Gradually, they sold their generation plants and started purchasing bulk power from other companies, while still continuing to operate their local distribution systems. Many North Carolina cities eventually sold their distribution systems to the investor-owned utilities (IOUs) in North Carolina, completely leaving the power supply business. However, 74 cities in North Carolina, representing about 11.5 percent of the state's population, currently remain in the power supply business.

In the 1970s, when fuel and electricity prices were escalating at double-digit rates, 51 of those cities—now representing about 9 percent of North Carolina's population—concluded that they could better control their costs if they purchased their own generation capacity. At the same time, IOUs were seeking ways to complete their new plant construction programs without incurring all of the oncoming cost increases due to spiraling interest rates and construction costs.

Supported by state legislation and authorized by a statewide voter referendum, those 51 cities combined forces to jointly purchase and operate generation facilities. Thirty-two cities in eastern North Carolina joined to form NCEMPA and purchase capacity jointly

with Carolina Power and Light Company (CP&L). Nineteen cities in western North Carolina formed NCMPA1 to purchase capacity jointly with Duke Power Company (Duke Power). Other participants in that purchase included the North Carolina Electric Membership Corporation (NCEMC), representing most electric cooperatives in North Carolina.

The decision was ill fated from the beginning. The MPAs struck deals prior to construction of major new nuclear facilities only a short time before the disaster at the Three Mile Island plant in Pennsylvania. After that incident, federal regulators vastly changed construction requirements and regulations that contributed to construction cost overruns. In addition, customers' energy conservation measures lowered the cities' need for new generation capacity compared to their earlier expectations. The MPAs suffered other adversities too, like changes in federal accounting rules that lowered their revenues from the sale of unneeded power to CP&L and Duke Power.

Technology and fuel costs changed as well. In the years following MPA nuclear plant acquisitions, the industry witnessed considerable improvements in and cost reductions for conventional generation technologies, especially gas-fueled plants. In addition, during the years following the deregulation of natural gas supplies, the nation experienced steadily declining fossil fuel prices. Both factors have considerably lowered the cost of power from new generation plants. At this time, new plants can deliver power at prices that are more than 30 percent below the current costs of power from MPA generation facilities.

Even more unsettling is the fact that the retail cost of power from MPA generation facilities is expected to rise by more than 30 percent within the next 15 years. Much of that cost increase is due to the ultimate effects of debt that was accumulated, in part, to offset past MPA operating deficits and due to some plant operating cost increases.

In retrospect, the MPAs clearly pursued an undiversified and aggressive investment strategy that failed. They chose to invest almost exclusively in nuclear plants and purchased excess generation capacity in anticipation of future growth that occurred much slower than expected. At the same time, the IOUs managed

to diversify their generation mix away from nuclear plants, compared to their initial expansion plans. They did so, in part, by selling the MPAs a portion of their nuclear plants. This turned out to be a good business decision for the IOUs because it lowered their generation costs in succeeding years. Had fossil fuel prices, inflation, and plant construction costs continued their rapid escalation beyond the late 1970s, the MPA strategy would have been far superior. That did not occur.

As a consequence, North Carolina's two MPAs together have total liabilities of about $5.8 billion, well in excess of any reasonable market value of the assets they hold. Even if their generation capacity is assumed to have a market value equal to the values (net of past depreciation) that the MPAs show in their financial statements, they have a combined net worth of about –$3.4 billion. Their net worth is more negative if likely market values for generation assets are taken into account. Even so, the 51 member cities are fully obligated to collect the revenue required to repay all MPA debt, and the state of North Carolina is obligated to ensure that they do so. So the MPAs are certainly expected to continue meeting their debt payments.

Thus, the burden of all this debt falls on the retail customers in the 51 cities that are members of the MPAs. Each of those cities owns a fixed share of MPA debt. Because of variations in economic growth since the formation of the MPA and other factors, there is wide variation in the debt burden per capita among the 51 cities. The average debt amount is about $8,500 per person and about $15,900 per customer in those cities. Revenues from the sale of electricity by the member cities secure this debt. The Local Government Commission (LGC) of the state of North Carolina has statutory authority to assume full control of the finances of any member city that defaults on its debt service payments.

Fortunately, the state of North Carolina and the stakeholders affected by the MPA debt problem have a large number of reasonable options for resolving this problem, even though all the options will require considerable sacrifice. Each option imposes a burden on all stakeholders, but the burden to individual stakeholders varies significantly from one option to another.

We have identified four policy options that we call the Status Quo, Debt Relief, Divestiture, and Dissolution. The Status Quo maintains current institutional arrangements and management of the assets now controlled by the MPAs and their member cities. It is a policy that portends increasingly difficult circumstances for the MPA member cities in the years ahead, particularly if and when the state moves to retail competition for generation services.

Each of the other three policy options that we have offered represents a full menu of variations. Each option has a large number of attributes, and each attribute can be selected from among several alternatives. For example, Divestiture calls for the sale of MPA generation assets and could require any of a number of financing alternatives, cost-sharing arrangements for the payment of MPA debt remaining after the asset sales, and methods of payment of those assigned cost shares.

The three alternative policy options are qualitatively different from each other in terms of the institutional arrangements and control of the electric system assets now owned by the MPAs and their member cities. Variations of the Debt Relief policy are closest to those that have been advanced by ElectriCities (e.g., electricity surcharges and price freezes). None of the Debt Relief options involve much change in the ownership and control of MPA and member city assets, except for possible changes in the governance of the MPAs.

To provide a full view of possible alternative policies, we did not restrict our attention to those that preserve the MPAs or member city ownership of their electric systems. Accordingly, we examined the Divestiture option, which entails the disposition of all MPA generating assets as well as fundamental changes in the role and operations of the MPAs. Beyond that, we examined the Dissolution option, which would involve the disposition of both the MPA generating assets and most or all of the member city electric systems.

Our review of the four policy options uses three levels of exposition. First, we provide a fairly comprehensive, but general, discussion of the four options. That discussion describes many alternative potential sources of revenue to retire the MPA debt and characterizes several possible variations of the features that could

be incorporated into the three policies that represent alternatives to the Status Quo.

Our second level of exposition develops and illustrates a structure for completing a *qualitative* analysis of the three policy alternatives. First, we define specific versions of each of the three policy alternatives—Debt Relief, Divestiture, and Dissolution. One or more of these versions may, with some added refinement, be sensible options for further examination. Then we identify seven groups of affected stakeholders:

- member cities,
- MPAs,
- IOUs,
- electric cooperatives and other electric suppliers,
- the state of North Carolina,
- MPA bondholders, and
- the federal government.

Each of the organizations in this list of stakeholders represents both the organization and all the individuals they serve or employ. For each of these stakeholder groups, we qualitatively detail the prospective advantages and disadvantages to them of implementing each policy alternative. We recommend this model of qualitative analysis for any other policy variations that the Study Commission and stakeholders may wish to consider.

Our third level of exposition provides a *quantitative* analysis of the possible implementation of the three specific policy alternatives. In the quantitative analysis, we show how each of the policies could be structured and how the costs would vary for each of the major stakeholders.

Although the MPA debt problem may seem overwhelming, it is encouraging that the state has a large number of reasonable policy options to resolve the problem, as identified in this report. Some of the options that we identify seem more politically balanced than others in terms of the relative sacrifices required of the various stakeholder groups. But we do not advocate any of the alternative policies. Instead, we have sought to identify a rich set of options

and demonstrate methods for analyzing them. The most important part of any future analyses is to determine carefully the advantages and disadvantages, both qualitatively and quantitatively, for each of the policy options within each stakeholder group. It is the role of the Study Commission and the major stakeholders to weigh these advantages and disadvantages and to choose a policy option that, in their judgment, maximizes fairness to all the citizens of North Carolina and enhances the efficiency of electric service delivery in the state.

1 Introduction

In early 1998, the Study Commission on the Future of Electric Service in North Carolina contracted with Research Triangle Institute (RTI) to prepare a detailed study of the potential stranded costs that North Carolina electric utilities may experience under retail competition. At the outset the Commission recognized the complexity of stranded cost issues affecting the state's two municipal power agencies (MPAs), the North Carolina Eastern Municipal Power Agency (NCEMPA) and the North Carolina Municipal Power Agency 1 (NCMPA1), affiliated with ElectriCities. Accordingly, the Commission required that we also provide a detailed analysis of the issues affecting the MPAs and that we identify possible policy options. This volume seeks to fulfill that requirement and augments the discussion and detailed estimates of stranded costs that are reported for both MPAs and other North Carolina utilities in the other two volumes of this report on stranded cost issues for North Carolina—specifically in *Volume 2: Options and Issues* and *Volume 3: Estimates of Stranded Costs and Recovery Options.*

This volume contains four additional sections. Section 2 describes the evolution of the two power agencies, the predicament they face today, and their current financial condition. Section 3 provides relevant information about the North Carolina cities that are members of the two MPAs. It summarizes their demographics, power delivery costs, debt burdens, and possible revenue sources to repay their debt. Section 4 details the primary legal authority and obligations of the relevant stakeholders associated with the "ElectriCities problem." Section 5 identifies four policy options for coping with the problem, one of which is to maintain current

regulatory policies—we call that the Status Quo. We then proceed to detail and critique specific versions for each of the three alternatives to the Status Quo. Finally, Section 5 introduces implementation scenarios for each of these three specific alternative policies.

Several important caveats apply to the work presented in this report. First, we have attempted to provide an accurate overview of the historical and financial circumstances affecting the two North Carolina MPAs. Because it is a condensed overview, we were forced to omit many details that will have to be considered more carefully in further refinements of policy options that the Study Commission may wish to develop. Second, although we have sought to provide a comprehensive characterization of all possible policy options for coping with the MPAs' stranded cost issues, other contributors will doubtless identify several other policy variations and options that can be added to the list identified in this report. Third, we do not advocate any of the policy options that we have identified in this report. Our goal in this report is solely to identify a rich set of policy options and a structure and method for thinking about the alternatives. Our purpose is to better inform the debate about the alternatives and to assist in the evaluation of future policy variations that may evolve from discussions of our report. Fourth, the last part of this report offers specific versions of three of the policy options. The specificity of those policy versions requires many assumptions about such matters as asset values, available financing arrangements, and the feasibility of certain types of contracts. We believe that our assumptions are reasonable, but we cannot ensure the legality, practicability, or political feasibility of every detail. Our main purpose in developing those detailed policy versions is to illustrate how to develop a specific version of each alternative policy and to stimulate discussion and analysis of additional variations that may be of greater interest to the Study Commission and affected stakeholders.

2 North Carolina Municipal Power Agencies

The evolution of North Carolina's two municipal power agencies (MPAs), the North Carolina Eastern Municipal Power Agency (NCEMPA) and the North Carolina Municipal Power Agency 1 (NCMPA1), is attributable to institutions and forces that took shape nearly a century ago. In this section we first describe those forces briefly and then characterize the main factors that caused the predicament both agencies face today. The final section details their current financial condition.

2.1 BRIEF HISTORY OF MUNICIPAL POWER SYSTEMS IN NORTH CAROLINA

Municipal power systems have a long history in North Carolina. The first municipal power system in North Carolina was formed in Statesville in 1889. This power system predates all investor-owned utilities (IOUs) and electric cooperatives now serving North Carolina. In their early years, North Carolina municipalities built their own power supply systems to assure adequate service for their customers; they built both power generation plants and power distribution systems. Subsequently, as their generation facilities became obsolete, the cities found it more economical to purchase bulk power at wholesale, which they continued to distribute to their customers at retail. Over time, as the state's economy and population grew, some municipalities sold their distribution and generation facilities to the IOUs. However, many North Carolina

cities chose to retain and operate their systems. Today 74 cities in North Carolina own and operate municipal power systems; the population of those cities represents about 11.5 percent of North Carolina's total population.

The organization that ultimately became known as ElectriCities was formed in 1965 under authorization of the Electric Act of 1965. ElectriCities is a traditional trade association and provides the services that are typical of such an organization, including the development of legislation affecting municipal power systems and legal support to the member municipalities. The role of the organization expanded considerably over time, particularly after the formation of the MPAs. Today ElectriCities not only performs trade association duties, but also offers a wide range of training, marketing support, and actual distribution system management and operation on a subscription basis for its members.

ElectriCities has a wide variety of members, including both full members and associate members. Full members are entitled to vote for directors; they must be a North Carolina entity that has passed a resolution to join. Associate members are nonvoting, may join based on a simple application, and may be located outside North Carolina. ElectriCities' full members include 61 North Carolina municipalities, of which 51 are participants in one of the two North Carolina MPAs. ElectriCities also represents 28 associate members: 11 additional cities in North Carolina, four cities in South Carolina, 11 cities in Virginia, and two members of the consolidated University of North Carolina system. ElectriCities represents 72 of the 74 municipal power systems in North Carolina.

2.2 EVOLUTION OF THE POWER AGENCIES

In the early 1970s, municipal power systems, like other suppliers worldwide, were shocked by very large fuel price increases. At the time, most of North Carolina's municipal systems were bulk power customers, buying most or all of their power from IOUs to meet their customers' needs. Their wholesale electricity rates rose 530 percent in the 12 years from 1970 to 1982, primarily due to large increases in fossil fuel prices.

Because of these rapidly rising costs, the municipalities concluded that acquiring their own generation was the best source of long-term cost relief. In particular, they and other utilities of that time were especially attracted to nuclear generation plants, which were projected to become a low-cost source of power. Most observers thought that nuclear capacity would be added at $500 per kilowatt of capacity, roughly twice the cost of coal plants at the time. They thought this initial cost premium for nuclear plants was justified because of large savings in operating costs compared to competing fossil-fueled plants.

The North Carolina municipal utilities, electric cooperatives, and the IOUs were attracted to joint investment in nuclear power plants. They considered other factors besides fossil fuel price increases:

- The demand for electricity during that period grew at double-digit rates and was expected to continue growing at those rates.
- Because of the expected load growth, the IOUs were planning large capacity expansions, including nuclear plants.
- Because of the high interest rates and plant construction cost escalation at that time, the IOUs were searching for cheaper ways to complete their new plant construction programs.

Nonetheless, North Carolina municipalities failed in their early attempts to acquire ownership in nuclear plants. In 1968, 11 western North Carolina cities filed an anti-trust suit for partial ownership in the Oconee nuclear plant. Fourteen cities in eastern North Carolina also filed an anti-trust suit for partial ownership of the Brunswick nuclear plant in 1969. Both groups were denied because the Atomic Energy Commission did not have the authority to sanction the purchases. However, the Atomic Energy Act of 1970 allowed the Nuclear Regulatory Commission to change its rules for licensing nuclear plants. This change was the first step in a series of changes that eventually enabled the cities to buy into nuclear generation.

The second step was taken in 1975 when the North Carolina General Assembly passed Chapter 159B, the Joint Municipal Electric Power and Energy Act. The General Assembly determined

that municipalities were important suppliers of electricity and that the state should allow them to jointly finance, develop, own, and operate appropriate generation and transmission facilities.

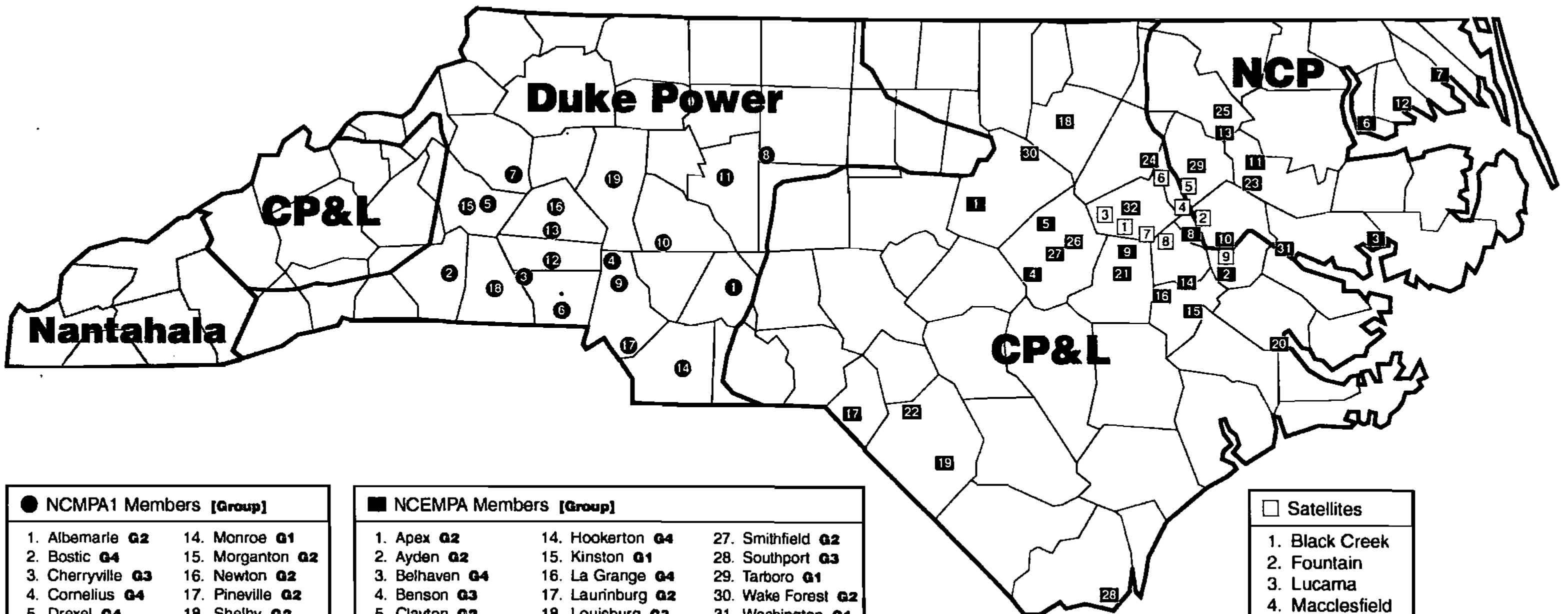
The North Carolina power agencies were formed after the passage of the Act. However, final authorization for their joint ownership of generation did not come until 1977 when North Carolina voters approved a constitutional amendment that allowed the cities to jointly own generation with private entities.

The formation of the power agencies began after the passage of Chapter 159B in 1975. In the early stages of their formation, three separate agencies were proposed, essentially formed of cities located within the service territory boundaries of each of North Carolina's three major IOUs. However, the agencies initially numbered 2 and 3, which comprised 32 cities located within the boundaries of North Carolina Power and Carolina Power and Light (CP&L), were combined to form NCEMPA. The other, NCMPA1, was formed of 19 cities that are located within the service territory boundaries of Duke Power. Today, both of these MPAs continue to serve their original member cities. The names and locations of all 51 member cities are shown in Figure 2-1. We separated the member cities of each agency into four groups based on their total gigawatt hour (GWh) sales. The sales levels of cities in each of the four groups are reported in the legend of Figure 2-1.

As discussed further below, both CP&L and Duke Power built some generation capacity that is jointly owned by the two MPAs. CP&L was associated with NCEMPA and Duke Power with NCMPA1. The structured relationship among these two IOUs, the two MPAs, ElectriCities, and the MPA member cities was put in place in the late 1970s and early 1980s and remains largely unchanged today, as depicted in Figure 2-2. The figure also shows the names and locations of nine cities that until recently purchased all their power from NCEMPA member cities. Four of the nine cities have since built power delivery facilities and started buying bulk power directly (see Section 3.2 for details).

A Board of Commissioners that consists of one representative from each member city governs each MPA. Representatives on these boards have votes that are proportionate to each city's share of asset and debt ownership. In turn the Boards of Commissioners

Figure 2-1. ElectriCities Members and Satellites



● NCMPA1 Members [Group]

1. Albemarle G2
2. Bostic G4
3. Cherryville G3
4. Cornelius G4
5. Drexel G4
6. Gastonia G1
7. Granite Falls G3
8. High Point G1
9. Huntersville G4
10. Landis G3
11. Lexington G1
12. Lincolnton G3
13. Maiden G3
14. Monroe G1
15. Morganton G2
16. Newton G2
17. Pineville G2
18. Shelby G2
19. Statesville G1

G1 = >386 GWh
G2 = 91–291 GWh
G3 = 33–87 GWh
G4 = <30 GWh

■ NCEMPA Members [Group]

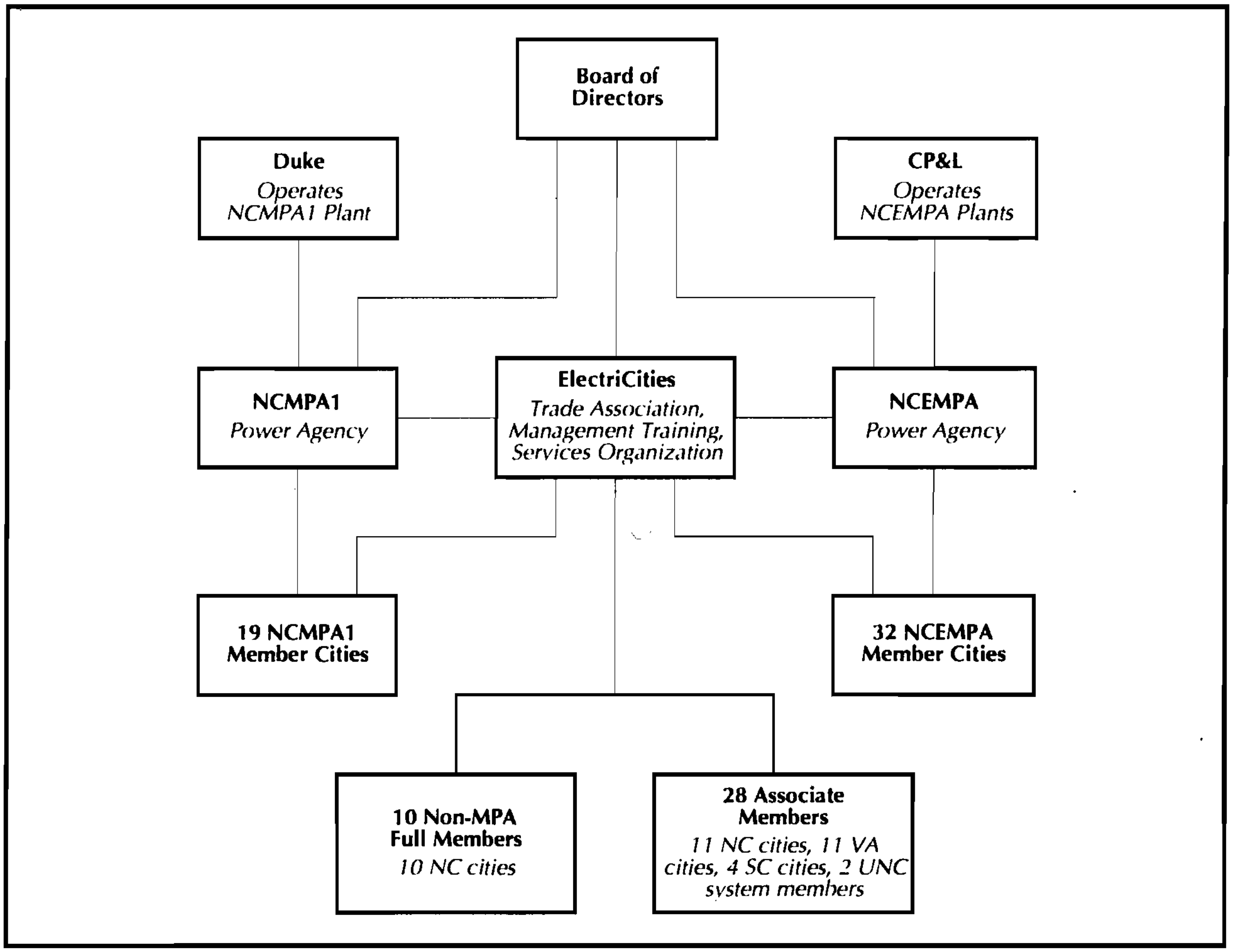
1. Apex G2
2. Ayden G2
3. Belhaven G4
4. Benson G3
5. Clayton G2
6. Edenton G2
7. Elizabeth City G2
8. Farmville G3
9. Fremont G3
10. Greenville G1
11. Hamilton G4
12. Hertford G4
13. Hobgood G4
14. Hookerton G4
15. Kinston G1
16. La Grange G4
17. Laurinburg G2
18. Louisburg G3
19. Lumberton G1
20. New Bern G1
21. Pikeville G4
22. Red Springs G3
23. Robersonville G4
24. Rocky Mount G1
25. Scotland Neck G3
26. Selma G3
27. Smithfield G2
28. Southport G3
29. Tarboro G1
30. Wake Forest G2
31. Washington G1
32. Wilson G1

G1 = >239 GWh
G2 = 64–238 GWh
G3 = 27–50 GWh
G4 = <26 GWh

□ Satellites

1. Black Creek
2. Fountain
3. Lucama
4. Macclesfield
5. Pinetops
6. Sharpsburg
7. Stantonsburg
8. Walstonburg
9. Winterville

Figure 2-2. Organizational Relationship Among ElectriCities, the MPAs, and Member Cities



elect six members to the overall Board of Directors for a total of 12 members. The North Carolina municipalities that are members of ElectriCities but not power agency members elect two additional members of the Board of Directors. The ElectriCities Board of Directors operates much like an executive committee on behalf of both MPAs and ElectriCities.

2.3 THE POWER AGENCY PREDICAMENT

The series of decisions leading to the formation of the MPAs and their ownership of generation assets was fateful. In fact, most of the key assumptions and projections that led to those decisions turned out to be wrong. Thus, today the electric rates of the cities that are members of the MPAs are more than 20 percent higher

than those charged to CP&L and Duke Power customers and in some cases more than 35 percent higher.[1] Four factors account for these rate differences:

- ***Huge Construction Cost Overruns.*** As it turned out, the MPAs were buying shares of nuclear plants that were under construction at the time of the incident at Three Mile Island. After that incident, the Nuclear Regulatory Commission imposed much tougher regulations on all nuclear plants then under construction as well as any future nuclear plants to be constructed. These regulations, among other things, led to final construction costs that were as much as four times the initial estimates. Yet under their purchase contracts the municipalities were obliged to pay their share of all construction costs. As a result, they bought into the last and most expensive nuclear power plants constructed.
- ***Decline in Load Compared to Forecast.*** During the late 1970s, the nation experienced double-digit load growth, which was predicted to continue throughout the 1980s. Also, fuel prices had been increasing because of the actions of the Organization of the Petroleum Exporting Countries and other factors. In light of this situation, large-scale capacity purchases seemed a good option. However, increases in energy efficiencies at the customer level caused load to increase significantly less than had been predicted. Therefore, the municipalities had purchased more generation than they actually needed. The debt on this excess capacity is partially responsible for the MPAs' higher rates.
- ***Decline in Sell-Back Price.*** Because the municipalities were building extra capacity in anticipation of future growth, and to help relieve the cost burden of that capacity in the early years of the plants, the IOUs agreed to buy back all or a percentage of the power in excess of the power agencies' needs. Several factors have affected the sell-back price and quantity. The 1986 Tax Reform Act required IOUs to lower their "buyback" prices and lengthen the sell-

[1] See RTI's report to the Legislative Study Commission, *Task 2: Rate Comparisons*, July 1998, pages 3-13 through 3-18 and Appendix D. Caution must be used in making comparisons of overall prices between the IOUs and member cities due to a number of factors related to the mix and geographic density of customers. For example, most MPA customers are residential. Compared to CP&L residential customers, NCEMPA residential customers now pay about 25 percent higher rates; compared to Duke residential customers, NCMPA1 residential customers pay about 23 percent more. The premiums paid by MPA cities' industries and commercial customers are generally more than 30 percent above Duke and CP&L prices.

back period due to their treatment of income taxes. This change led to short-run revenue losses to the MPAs. Also, in more recent years, the sell-back contracts have begun to expire or to be renegotiated, thus lowering the amount of excess capacity that the MPA can sell back.

- ***High Interest Rates.*** During the 1980s interest rates rose to historically high levels. These increases occurred during most of the construction phase for capacity purchased by the MPAs, which caused higher financing cost than initially expected.

As a result of these factors, the MPAs have continued to struggle since their inception. Their challenge has been to deliver electricity to their members at a price that is comparable to rates that other utilities within the region charge their customers. Despite the MPAs' tax-exempt status and their accompanying low cost of debt, the battle has been lost. In the early years, the agencies paid net interest expenses of about $1.5 billion (both before and after commercial operation of their generating units) by borrowing additional funds, temporarily keeping rates low.[2] As a consequence they carry the cumulative value of those uncharged costs as an asset—unfortunately a worthless asset. Their financial problems are immense, as summarized below.

2.4 FINANCIAL CONDITION OF THE POWER AGENCIES

Both of the power agencies are fully capitalized by debt—neither has any common or preferred stock issues. Since their inception, both have issued tax-exempt bonds and other debt instruments under the aegis of the Local Government Commission (LGC) of the state of North Carolina. The LGC participates in the debt placements. (See Section 4 for more details on the legal and regulatory relationship of the MPAs to the LGC.) Currently, the total amount of outstanding debt that is owed by the two power agencies is about $5.8 billion and represents about 28 percent of the total state and local debt in North Carolina. Two important factors affect the MPAs' debt:

[2]About two-thirds of this cost was incurred prior to commercial operation and was similar to a practice called Allowance for Funds Used During Construction (AFUDC) that was also used by IOUs. Total capitalized interest was about $2 billion, but about one-fourth of that was offset by interest earnings on unspent bond proceeds.

- ***Backed by Electricity Revenues.*** The bonds issued by the two power agencies are not like other municipal bonds. These bonds are not backed by the municipalities' tax revenues. Instead, the bonds are backed by revenues the power agencies receive from sales of electricity to the member cities. And each member city has a fixed debt share (called the "initial project share") that it is responsible to pay. The North Carolina LGC has the right to step in and ensure that the bonds are retired by the member cities. So the true liability for all of the MPA debt resides with the electricity customers within the member cities. They are obliged by state law and by contract to retire all the debt acquired by their city representatives through their joint actions with the power agencies.

- ***Issued at High Rates.*** At the time that the power agency bonds were issued, the nation was experiencing some of the highest interest rates in its history. In borrowing funds at those rates, the agencies became saddled with extremely high debt service costs—albeit much lower, due to their tax-exempt status, than was the case for private-sector borrowers at the time. By refinancing, the agencies have considerably lowered the average interest rate on their debt. However, this has led to refinancing costs, which added to the total debt burden.

In the following sections we provide an overview of the assets, liabilities, net worth, and other financial details that summarize the financial condition of the power agencies.

2.4.1 MPA Electric Plant Ownership

Nuclear units dominate the generation capacity owned by the MPAs. As shown in Table 2-1 the NCEMPA owns a total of 639.7 MW of capacity. All of that capacity is operated and partially owned by CP&L. One-third of the total is coal-fired and includes portions of two separate plants. The remaining two-thirds comprise ownership shares in two nuclear plants.

The total original cost of NCEMPA's plant in service as of December 31, 1997, was $1,415 million, or an average purchase cost of $2,212/kW—more than four times the amount expected in the planning stages. Those costs were dominated by the nuclear plants, especially the Harris plant whose initial cost was over $4,700/kW, an unusually expensive facility.

Table 2-1. NCEMPA and NCMPA1 Capacity Ownership

	Capacity (MW)	Ownership	
		Share (%)	Capacity (MW)
NCEMPA			
Coal Units			
Roxboro Unit 4	700	12.94	90.6
Mayo Unit 1	745	16.17	120.5
Nuclear Units			
Brunswick Unit 1	790	18.33	144.8
Brunswick Unit 2	790	18.33	144.8
Harris Unit 1	860	16.17	139.0
Total Capacity Ownership			639.7
NCMPA1			
Nuclear Unit			
Catawba Unit 2	1,129	75.00	846.8
Total Capacity Ownership			846.8

Table 2-1 also shows that NCMPA1 owns a total of 846.8 MW of capacity. That represents a 75 percent share of Unit 2 at the Catawba plant, which is operated by Duke Power. The original cost of that capacity was $1,427 million or about $1,686/kW.

2.4.2 MPA Assets

Standard accounting requires that the total reported (book) value of all assets must equal the total value of all company debt and equity, such as common and preferred stock. As public agencies, neither MPA has any equity, except for negligible amounts of "retained earnings." Thus, the total book value of their assets equals the total amount of their debt, which was just over $6 billion for the two agencies combined at the end of 1997. (By the date of this report that debt has been reduced to about $5.8 billion.) NCEMPA's assets (and total debt) at that time were $3.62 billion, and NCMPA1's were at a little over $2.4 billion, as indicated in Table 2-2.

Table 2-2. North Carolina MPA Assets, December 31, 1997

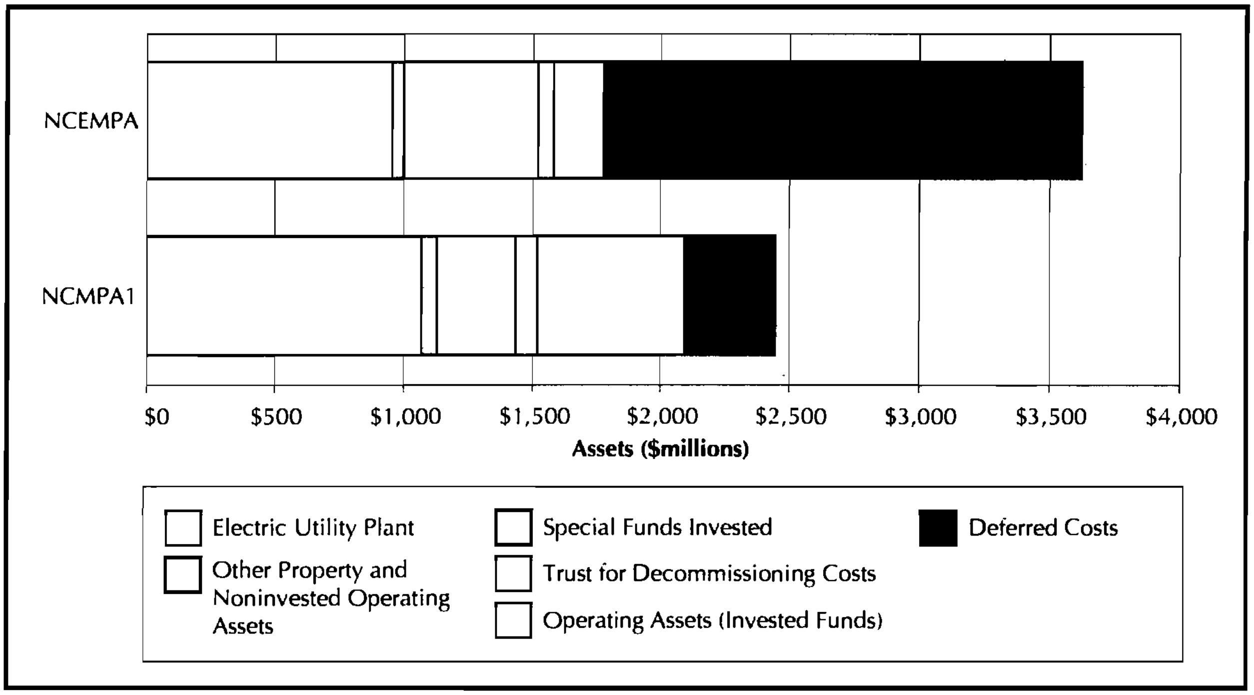
	NCEMPA		NCMPA1	
	Value ($thousands)	Asset Share (%)	Value ($thousands)	Asset Share (%)
Asset Category				
1. Electric Utility Plant	$950,679	26.3	$1,066,360	43.6
2. Other Prop. & Non-invested Oper. Assets	$49,412	1.4	$61,173	2.5
3. Special Funds Invested	$519,695	14.4	$304,368	12.4
4. Trust for Decommissioning Costs	$57,132	1.6	$86,245	3.5
5. Operating Assets (Invested Funds)	$198,191	5.5	$573,370	23.5
6. Deferred Costs	$1,844,635	51.0	$353,258	14.4
Total Assets	$3,619,744	100.0	$2,444,774	100.0
Total Intangible Assets (=(3) + (4) + (5) + (6))	$2,619,653		$1,317,241	
Less:				
Deferred Costs (=(6))	$1,844,635		$353,258	
"Market Value" of Intangible Assets	$775,018		$963,983	

Table 2-2 details six asset categories for both MPAs.[3] Categories (1) and (2) are "tangible" assets, essentially their share of the plant and equipment. The reported book values of (1) and (2) equal their original purchase costs less the total of their depreciation write-offs in prior years. The remaining categories (3) through (6) are "intangible" assets that include invested funds and deferred costs. Invested funds are required for several reasons—to comply with the terms of MPA bond issues, to comply with federal requirements for funding future decommissioning costs, and to provide operating capital. The approximate market values of their intangible assets, shown at the bottom of Table 2-2, are the total book value of all intangibles less the book value of deferred costs, which have no market value.

[3]None of the distribution assets of the MPA member cities are included because municipal electric systems are fully owned by those cities. Nonetheless, the member cities are ultimately liable for all MPA debt—see Section 4.3 for details.

Figure 2-3 summarizes the asset side of the balance sheet for both agencies. It shows each of the major asset components, which are quite different in several respects. Most significantly, NCEMPA has substantially more deferred costs—over half of NCEMPA's assets are composed of deferred costs. The combined total dollar amount of deferred costs for the two agencies is almost $2.2 billion.

Figure 2-3. North Carolina MPA Assets, December 31, 1997



Deferred costs are worthless as marketable assets. They represent the cumulative value of operating deficits incurred by each agency since their inception. Those deficits include the cumulative cost of depreciation, which did not constitute an actual cash outlay. Therefore, the amount of funds borrowed to finance these deferred costs is approximately equal to their total deferred costs less cumulative depreciation. For NCEMPA, the amount of deficits financed to date has been about $1.4 billion. But for NCMPA1 the amount of operating deficits financed is essentially zero.

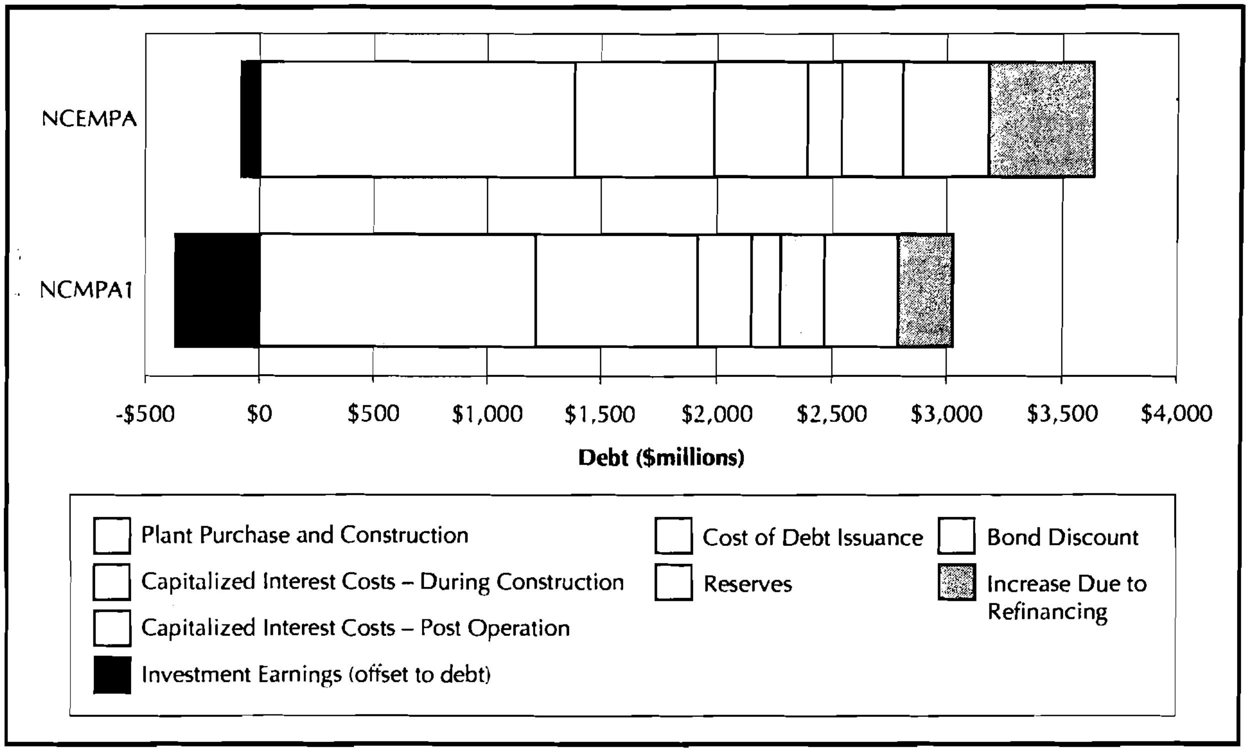
The agencies are also different in terms of the amount of invested funds they hold and in terms of the stated value of their plants. NCMPA1 holds a significantly higher amount of invested funds—essentially marketable securities that are paying interest to the

MPAs. And the remaining undepreciated value of their plant in service is also higher than for NCEMPA.

2.4.3 MPA Debt

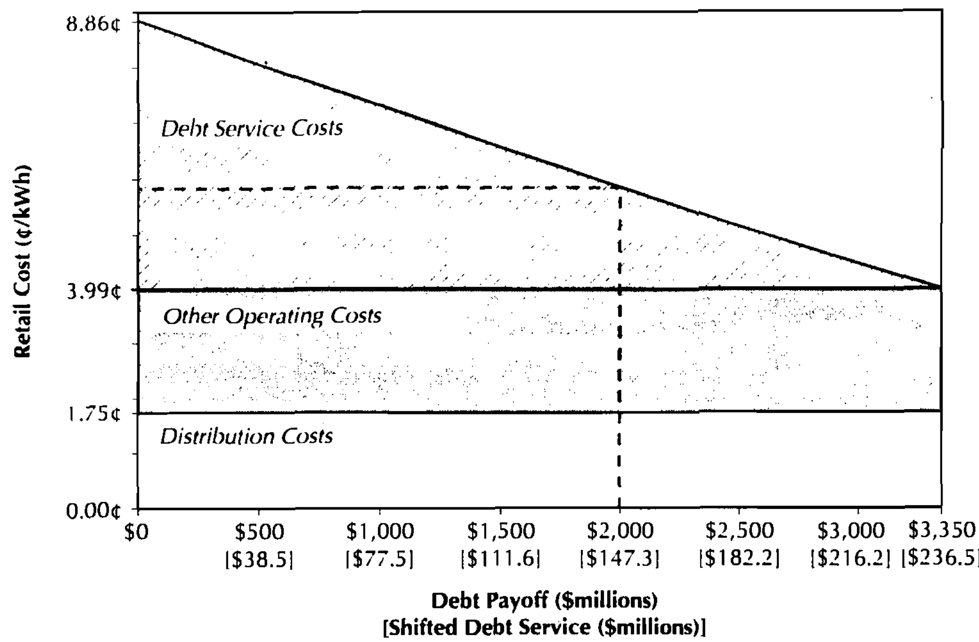
More than half of the MPA debt was incurred to pay for financing costs rather than actual plant purchase and construction.
Figure 2-4 shows the sources of the total debt burden for each of the power agencies. The white components in each bar represent the actual purchase costs for power plants. Most of the remaining debt was borrowed to cover interest costs that were not covered by electricity revenues and to pay the costs of reissuing debt, albeit at lower interest rates.

Figure 2-4. North Carolina MPA Debt by Source, 1997



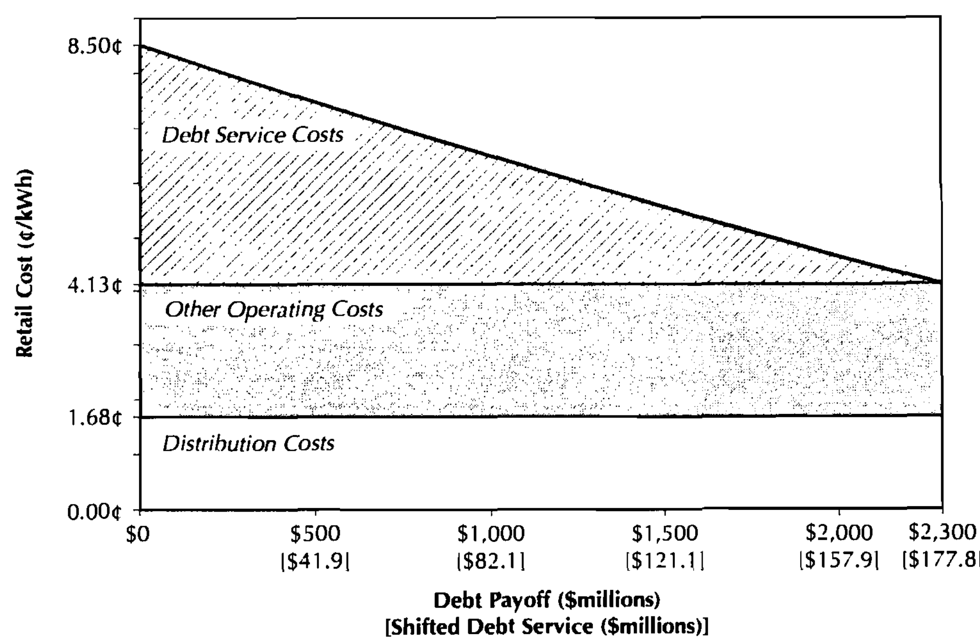
Figures 2-5 and 2-6 show the relationship between the amount of debt held by each agency and the amount the member cities must charge in 1998, on average, to cover their costs. For example, NCEMPA member cities would have had to charge an average

Figure 2-5. Effect of Debt Payoffs on Total Power Delivery Costs for NCEMPA Member Cities, 1998



Note: The actual retail rate was 8.51¢/kWh. The difference between the retail rate and retail cost, 0.35¢/kWh, was paid from the Rate Stabilization Fund.

Figure 2-6. Effect of Debt Payoffs on Total Power Delivery Costs for NCMPA1 Member Cities, 1998



Note: The actual retail rate was 7.63¢/kWh. The difference between the retail rate and retail cost, 0.87¢/kWh, was paid from the Rate Stabilization Fund.

retail price of 8.86¢/kWh to cover all their costs, as shown in Figure 2-5.[4] That cost is composed of three parts—local distribution costs (1.75¢/kWh); other MPA operating costs such a labor, fuel, equipment, and current liability costs (2.24¢/kWh); and long-term debt service costs to the MPAs, consisting primarily of principal and interest payments (4.87¢/kWh). The numbers on the vertical axis show the sum of these components, for example, 3.99¢/kWh is the sum of local distribution costs and other operating costs, and 8.86¢/kWh is the sum of all three components.

The horizontal axes in Figures 2-5 and 2-6 show hypothetical amounts of debt payoff and debt service costs. The numbers at the far right show current long-term debt and debt service costs. For example, Figure 2-5 shows that NCEMPA has $3.35 billion in long-term debt and that it costs them $236.5 million per year to make interest and principal payments on that debt. If NCEMPA were relieved of $2 billion of that debt, NCEMPA's debt service costs would decline to $147.3 million/year. As shown by the dashed line in the figure, that amount of debt payoff would allow NCEMPA member cities to cover all their remaining costs by charging an average of about 6¢/kWh—a cost reduction of about 2.9¢/kWh. In general, NCEMPA costs in 1998 would decline by about 1.45¢/kWh for every $1 billion in debt payoff, and NCMPA1's costs would decline by 1.9¢/kWh for every $1 billion in debt payoff.

Looking to the future possibility of retail competition, it may be useful to consider what level of costs the member cities would face without their MPA obligations. Specifically, consider a situation where (1) all of the MPA assets were disposed of and the MPAs are relieved of all their debt, and (2) each of the 51 member cities could purchase bulk power in the open market. Assuming no significant change in their administration costs, the member cities could then lower their average retail electricity prices to the sum of their current distribution costs and delivered bulk power purchase prices. At current delivered bulk power prices of about 3.5¢/kWh and their average distribution costs of 1.72¢/kWh, they could lower

[4]As noted in both Figures 2-5 and 2-6, the member cities' actual retail prices were below retail cost because the MPAs sold electricity to member cities at prices that were subsidized by withdrawals from their Rate Stabilization Funds included in asset category (5), Table 2-2.

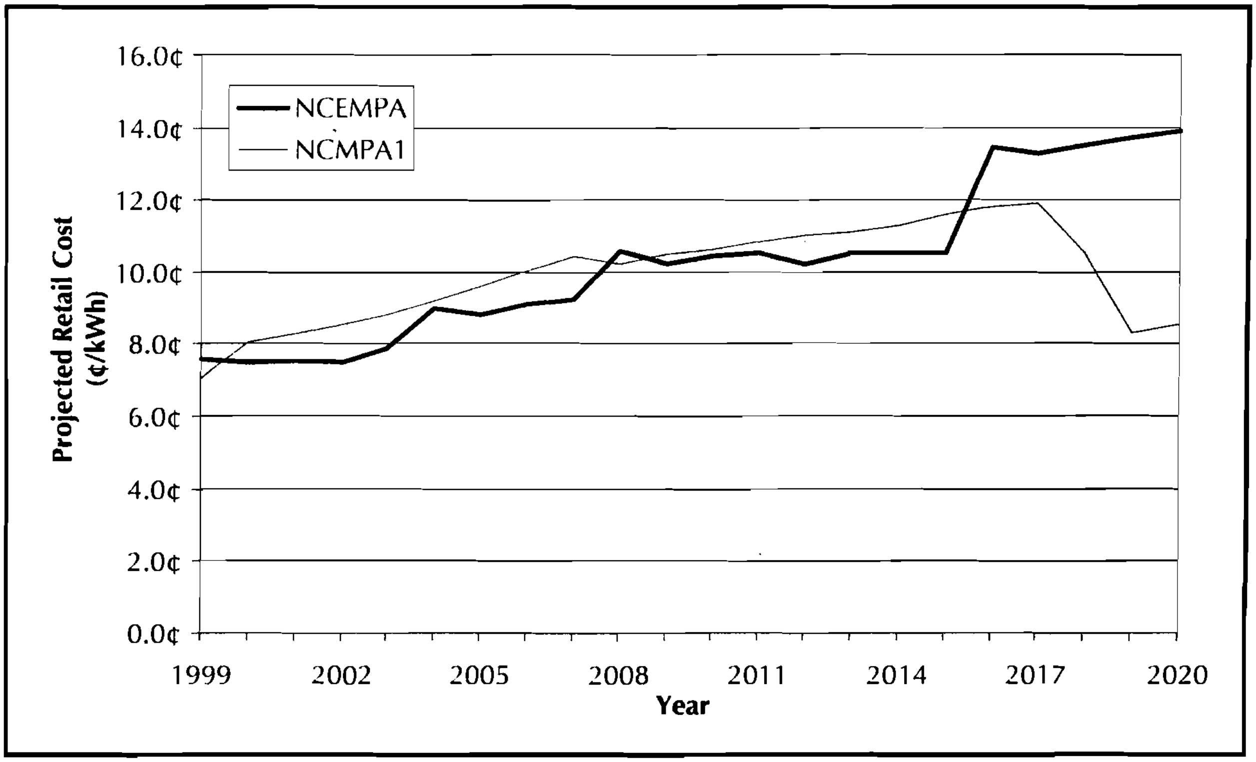
their average prices to about 5.22¢/kWh—about a 40 percent reduction.

We cannot provide a precise analysis of MPA costs in future years for two key reasons. First, no one knows the future costs of supplemental bulk power purchases needed to meet total demand by the MPA members. Second, we do not know the amount of revenues and kWh sales that the MPAs will receive from Duke and CP&L in future sell-back arrangements. However, from our stranded cost analysis, we do have future projections of **costs per kWh** for the electricity load that could be served by the remaining available MPA capacity (i.e., by the MPA plants that remain in service in future years). To get projections of the cost of power from those plants at the retail level, we added those projected costs/kWh to the current local distribution costs (1.75 and 1.68¢/kWh for NCEMPA and NCMPA1, respectively). Three important caveats apply to these projections:

- These projections are retail-level costs for power from existing MPA plants only. These costs are lower than shown in Figures 2-5 and 2-6 because the total kWh used in their calculation includes off-peak electricity that is sold back to Duke Power and CP&L at prices much lower than average retail prices.
- Supplemental power purchases will be made in future years to offset the projected loss of capacity from retired plants. Those purchases will likely be at competitive market prices and have the effect of lowering the average retail price. That effect is not reflected in our cost projections, since we project only the costs of power from the MPA-owned capacity that is projected to remain in service.
- Our projections are calculated after deducting projected contributions from the Rate Stabilization Funds for each MPA. These are set-aside funds incorporated in asset category (5) shown in Table 2-2 and are used to pay part of the MPAs' debt costs so their retail prices can remain lower.

Despite these caveats, the projections, shown in Figure 2-7, give an overall sense of production cost changes for the MPAs in future years. The projections suggest that NCEMPA's generation costs will remain at current levels until about 2003; rise to about 10.5¢/kWh by 2008 because of projected increases in operating costs; then remain fairly steady until 2015, projected as the last year of

Figure 2-7. Projected Retail Costs for Power Produced by MPA Plants



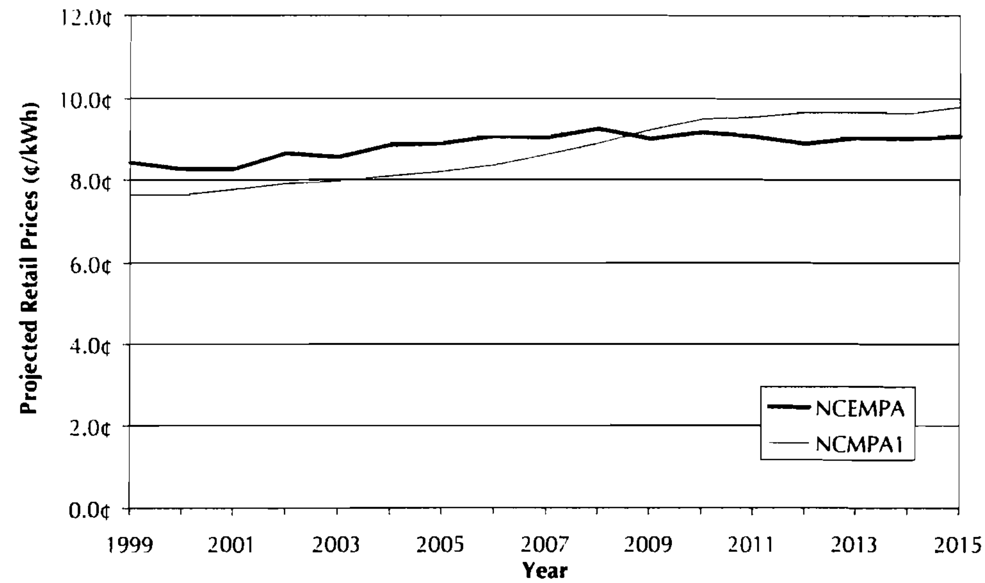
operation for the Brunswick plant.[5] The retirement of Brunswick causes their average retail costs to increase to between 13.5¢ and 14¢/kWh until 2020.

NCMPA1 costs are projected to rise more steadily from 7¢/kWh in 1999 to about 12¢/kWh until 2017. This cost increase is due to two factors: (1) steady depletion of the Rate Stabilization Fund used to offset revenue increases and (2) projected increases in operating costs for the Catawba plant. After 2017, NCMPA1's costs are projected to decline to about 8.5¢/kWh by 2020, because of the retirement of their debt.

Figure 2-8 shows the average retail prices projected for member cities within each MPA. These price projections are based on forecasts supplied by ElectriCities in their recent Summary of

[5]The operating license for the Brunswick plant could be extended and therefore affect these projections.

Figure 2-8. Projected Average Retail Prices for Member Cities



Note: These prices are based on recent projections of bulk power prices to member cities as provided by ElectriCities staff.

Projected Revenues and Expenses for the MPAs.[6] The projected 1999 average retail prices are about 7.6¢/kWh for NCMPA1 cities and 8.5¢/kWh for NCEMPA cities. During this 16-year period, the average annual rate of increase in projected average retail prices is 1.7 percent for NCMPA1 and 0.5 percent for NCEMPA.

2.4.4 MPA Net Worth

A typical indicator of financial condition is net worth. True net worth is the market value of an organization's assets less its liabilities. These values can be approximated for the MPAs under

[6]These price projections include the effect of withdrawals from the Rate Stabilization Funds, resulting in retail rates below cost. NCMPA1 projects Rate Stabilization Fund withdrawals through 2009. They project retail rates that are 10 to 12 percent below cost through 2001, then 6 to 8 percent below cost through 2006, and decline from 6 down to 1 percent below cost in 2009. NCEMPA projects that Rate Stabilization Funds will lower their rates by only 4 percent or so through 2001, and none after that. All of these price forecasts assume that the member cities distribution costs per kWh will remain constant at current levels. Of course, all of these projections are predicated on somewhat uncertain kWh sales levels, supplemental bulk power costs, actual distribution costs, and other assumptions incorporated in ElectriCities price forecasts.

several assumptions that require estimating the gross market value of the assets they hold.

The gross market value of assets for each MPA can be roughly estimated as the sum of the approximate market value of each asset category. Table 2-3 shows some hypothetical valuations under several assumptions:

- ➤ We include a wide range of generation capacity prices:
  - ✓ a zero value, which some observers claim to be accurate because of the understated future liability for decommissioning and decontamination;
  - ✓ the recent sale price per kW of capacity for the Three Mile Island nuclear plant, excluding the nuclear fuel sold;[7]
  - ✓ the recent sale price of Three Mile Island, including the fuel sold;
  - ✓ the approximate cost of a new combustion turbine plant as an indicator of replacement value with a peaking unit;
  - ✓ the current book value of the MPA plants (i.e., their currently stated accounting value); and
  - ✓ the plants' original purchase price.
- ➤ The market value of deferred costs is zero, and the value of nonutility property and equipment and operating assets other than invested funds is negligible enough to be valued at zero.
- ➤ All other invested assets have market values equal to their book values.

Table 2-3 is organized as follows. The first column in the table shows the six alternative estimates of capacity prices as just described. The second column is the product of the first column and the amount of capacity each MPA owns (from Table 2-1). The third column adds the value of intangible assets (from the bottom of Table 2-2) to the capacity values in column 2. The last column subtracts the MPA's outstanding debt from the "market values" in the third column, providing varying measures of "net worth." The

[7]We used the sale price of the Three Mile Island plant because it is the only nuclear plant that has recently been sold in the U.S.

Table 2-3. Approximate Net Worth of North Carolina MPAs at Hypothetical Capacity Valuations

	Capacity Price ($/kW)	Capacity Value ($millions)	"Market Value" ($millions)	"Net Worth" per kW Capacity	"Total Net Worth" ($millions)
NCEMPA					
Estimate of Capacity Price					
Zero	$0	$0	$775	–$4,447	**–$2,845**
TMI Hardware-Only Sale Price[a]	$26	$17	$792	–$4,421	**–$2,828**
TMI Fuel & Hardware Sale Price[a]	$115	$74	$849	–$4,332	**–$2,771**
Approximate CT Cost[b]	$350	$224	$999	–$4,097	**–$2,621**
Current Book Value	$1,486	$951	$1,726	–$2,961	**–$1,894**
Original Purchase Cost	$2,203	$1,409	$2,184	–$2,244	**–$1,436**
NCMPA1					
Estimate of Capacity Price					
Zero	$0	$0	$964	–$1,749	**–$1,481**
TMI Hardware-Only Sale Price[a]	$26	$22	$986	–$1,722	**–$1,458**
TMI Fuel & Hardware Sale Price[a]	$115	$97	$1,061	–$1,634	**–$1,383**
Approximate CT Cost[b]	$350	$296	$1,260	–$1,399	**–$1,184**
Current Book Value	$1,259	$1,066	$2,030	–$489	**–$414**
Original Purchase Cost	$1,686	$1,427	$2,391	–$63	**–$53**
Combined NCEMPA & NCMPA1					
Estimate of Capacity Price					
Zero	$0	$0	$1,739	–$6,196	**–$4,326**
TMI Hardware-Only Sale Price[a]	$26	$39	$1,778	–$6,143	**–$4,286**
TMI Fuel & Hardware Sale Price[a]	$115	$171	$1,910	–$5,966	**–$4,155**
Approximate CT Cost[b]	$350	$520	$2,259	–$5,496	**–$3,805**
Current Book Value	$1,357	$2,017	$3,756	–$3,450	**–$2,308**
Original Purchase Cost	$1,908	$2,837	$4,576	–$2,307	**–$1,489**

[a] TMI refers to the Three Mile Island nuclear power plant sold by GPU Inc. to AmerGen Energy Company as announced on July 17, 1998. AmerGen paid $77 million including fuel and $23 million for the reactor with 870 MW capacity.

[b] CT refers to a combustion turbine plant.

fifth column divides the last column by the amount of capacity each MPA owns to derive a net worth value per kW of capacity owned. Totals for the two MPAs appear in the bottom third of the table. The last column in that segment of the table shows, for example, that even when their capacity is valued at their original purchase cost, the MPAs' combined net worth is about –$1.5 billion.

Figures 2-9 and 2-10 show net worth estimates for both MPAs under the assumptions stated above. Even if generation assets were valued at book (i.e., at $1,357/kW, which is their original cost less accumulated depreciation), the aggregate net worth of the two MPAs is approximately –$2.3 billion (Figure 2-10). Assuming that the capacity has a net market value of zero means that their aggregate net worth is about –$4.3 billion. Assuming the Three Mile Island sale price including fuel, their aggregate net worth is approximately –$4.1 billion.

Both agencies are technically insolvent; i.e., both have liabilities well in excess of any reasonable market value of assets held. However, they are solvent in terms of their ability to repay debt because they have two substantial unstated assets. The main outside asset consists of the 51 member cities that are legally bound to collect electric revenues sufficient to repay all the MPA debt. The second is the authority and implicit obligation of the state of North Carolina to step in and take over the financial affairs of any North Carolina city that fails to meet these financial obligations.[8]

NCEMPA has a lower net worth than NCMPA1; e.g., at a zero capacity valuation its net worth is about –$2.8 billion versus –$1.5 billion for NCMPA1. Furthermore, in terms of net worth per kW owned, the value of NCEMPA is even more negative relative to NCMPA1.

[8]See Section 4.1 for details on the role and obligations of the Local Government Commission (LGC) of the state of North Carolina.

Figure 2-9. Approximate Net Worth of North Carolina MPAs at Hypothetical Capacity Valuations

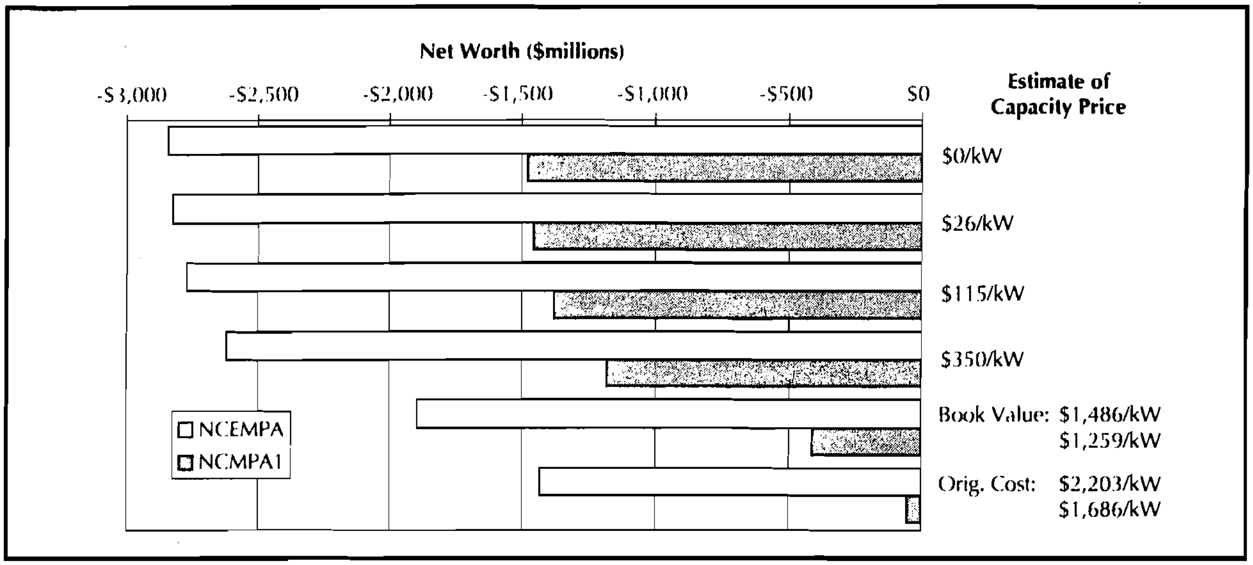
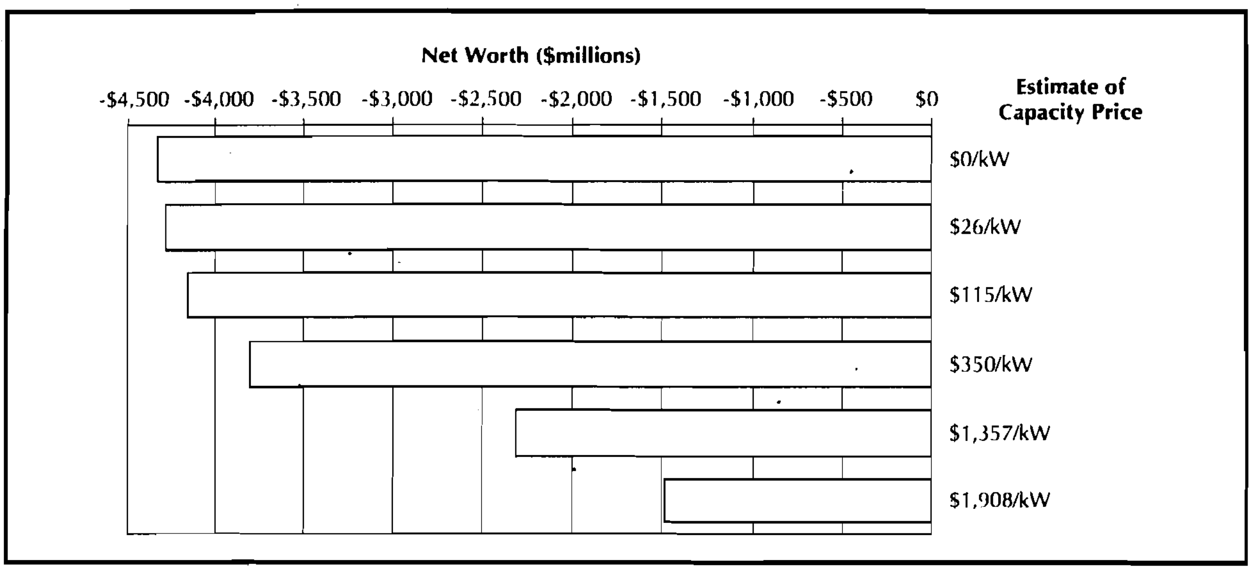


Figure 2-10. Approximate Combined Net Worth of North Carolina MPAs at Hypothetical Capacity Valuations



3 MPA Member Cities

The member cities govern the two municipal power agencies (MPAs). Each city owns a defined share of the MPA assets and owes a share of the MPA debt, so the economic health and prospects for these cities are key to the future viability of the power agencies. In this section we provide some additional details about the member cities, their power delivery costs, their debt burden, and possible sources of revenue to pay their debt.

3.1 DEMOGRAPHICS

The 51 member cities are all medium to small cities in North Carolina. The largest cities are High Point, Gastonia, Greenville, Rocky Mount, and Wilson—all ranging from 40,000 to about 70,000 in total population. The combined population of the North Carolina Eastern Municipal Power Agency (NCEMPA) cities is about 361,000 and about 218,000 for the North Carolina Municipal Power Agency 1 (NCMPA1). All together these cities account for about 9 percent of North Carolina's population.

The location of each member city is shown in Figure 2-1. Members of NCEMPA are located within the service territory boundaries of both North Carolina Power and Carolina Power & Light (CP&L), whereas all NCMPA1 members are located within the service territory boundaries of Duke Power.

Figures 3-1 and 3-2 show the relationship between the total population and the total number of customers for NCEMPA and NCMPA1, respectively.

Figure 3-1. Total Population and Number of Customers for NCEMPA Cities

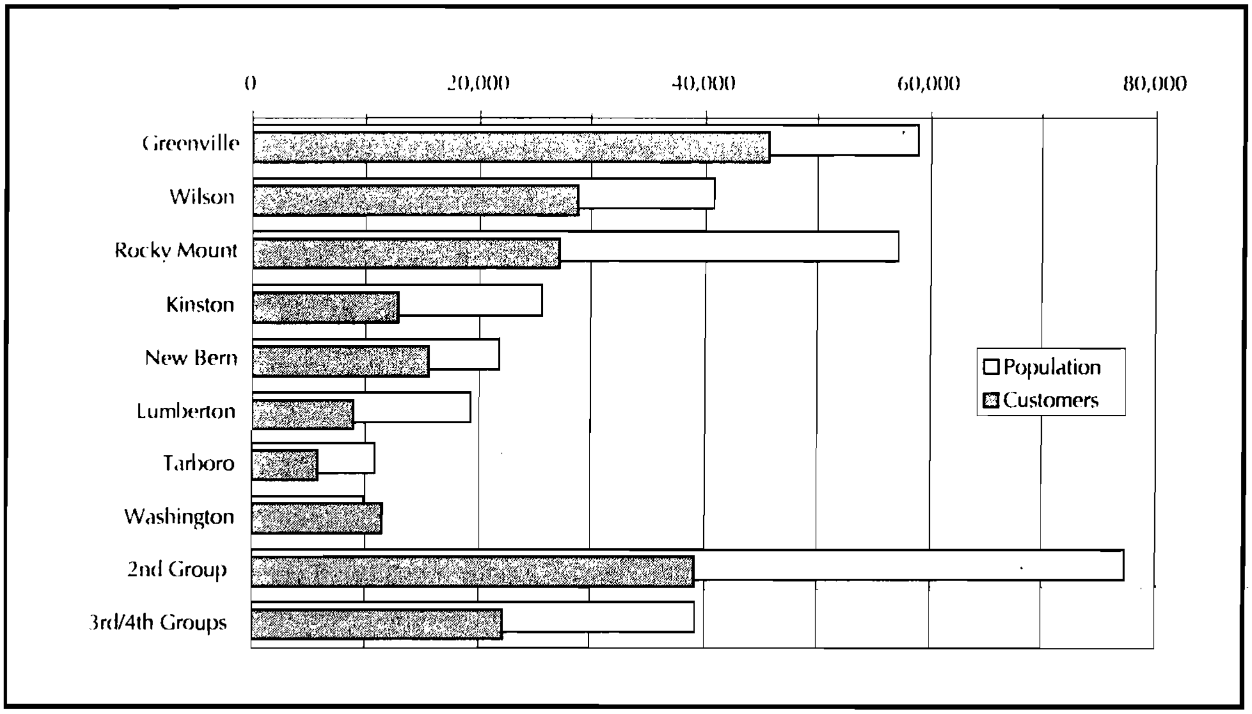
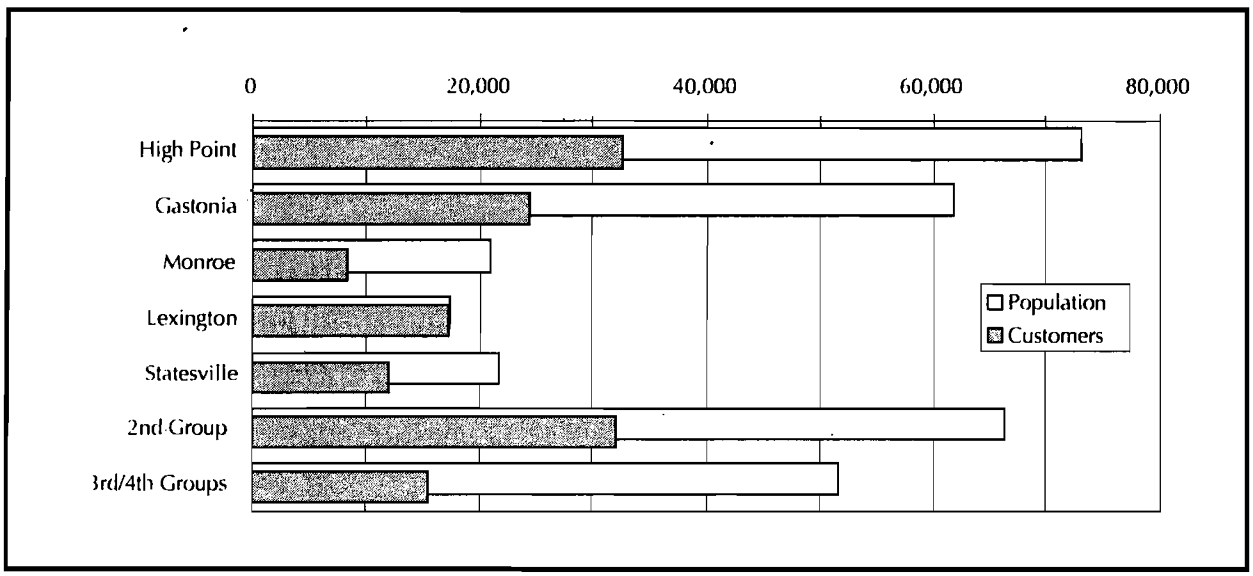


Figure 3-2. Total Population and Number of Customers for NCMPA1 Cities



These two figures show the names of only those cities within Group #1 for each agency. (See Figure 2-1 for the designation of cities in each group.) The second bar from the bottom of each figure shows data for the second group. And the bottom bar combines both the 3rd and 4th groups. The total population of the 3rd and 4th groups is less than that of the single 2nd or 3rd largest city within the first group.

NCEMPA has about 219,000 customers, NCMPA1 about 142,000 customers. The ratio of population to customers is 1.66 and 2.20 for those two agencies, respectively. The difference in this ratio may have been affected by the 1965 Electric Act, sometimes known as the Territorial Assignment Act (see Section 4). It had the effect of curtailing the number of customers that growing cities could add. Although member cities could annex new areas and thereby add population after passage of the Act, it restricted the cities from adding new electricity customers in some of those annexed areas. Instead, those customers have typically been served by another electricity supplier assigned to serve those locations.

3.2 POWER CONSUMPTION

For the year ending June 30, 1997, the customers of NCEMPA consumed a total of 5,951 GWh of electricity. The customers of NCMPA1 consumed 3,951 GWh. The total for the two agencies represents about 8.5 percent of the total electricity usage in North Carolina. Figures 3-3 and 3-4 depict the total electricity sales of the cities within each agency. It is clear that some cities have a relatively higher ratio of sales to customers. For some cities this would be due in part to a relatively higher proportion of commercial and industrial customers.

Sales to satellite cities also account for higher sales per customer. Currently, three NCEMPA cities sell bulk power to satellite cities. The city of Wilson sells to Macclesfield, Pinetops, and Walstonburg; the city of Greenville, to Winterville; and the city of Farmville, to Fountain. Until recently, the City of Wilson also sold power to Black Creek, Lucama, and Stantonsburg and the City of Rocky Mount, to Sharpsburg. But primarily because of the high prices that Wilson and Rocky Mount had to charge, those cities

Figure 3-3. Total Number of Customers and Electricity Sales for NCEMPA Cities

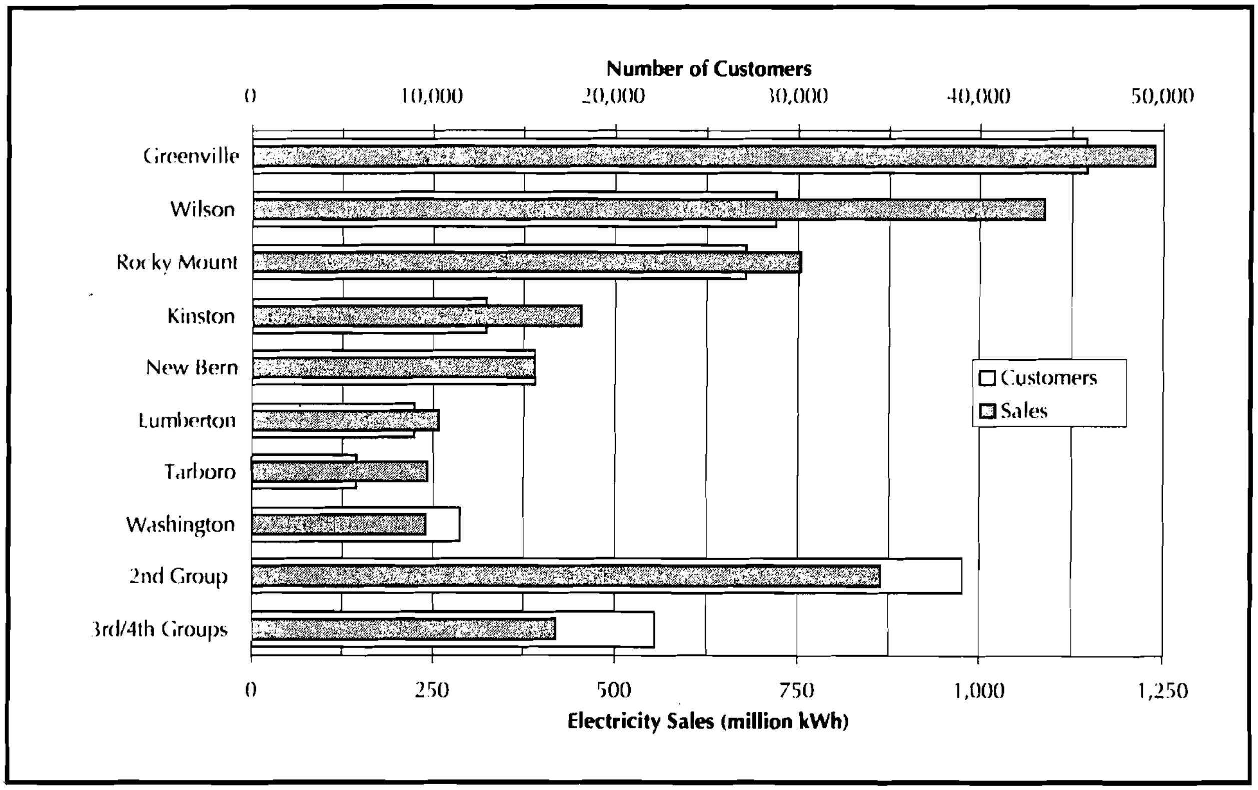
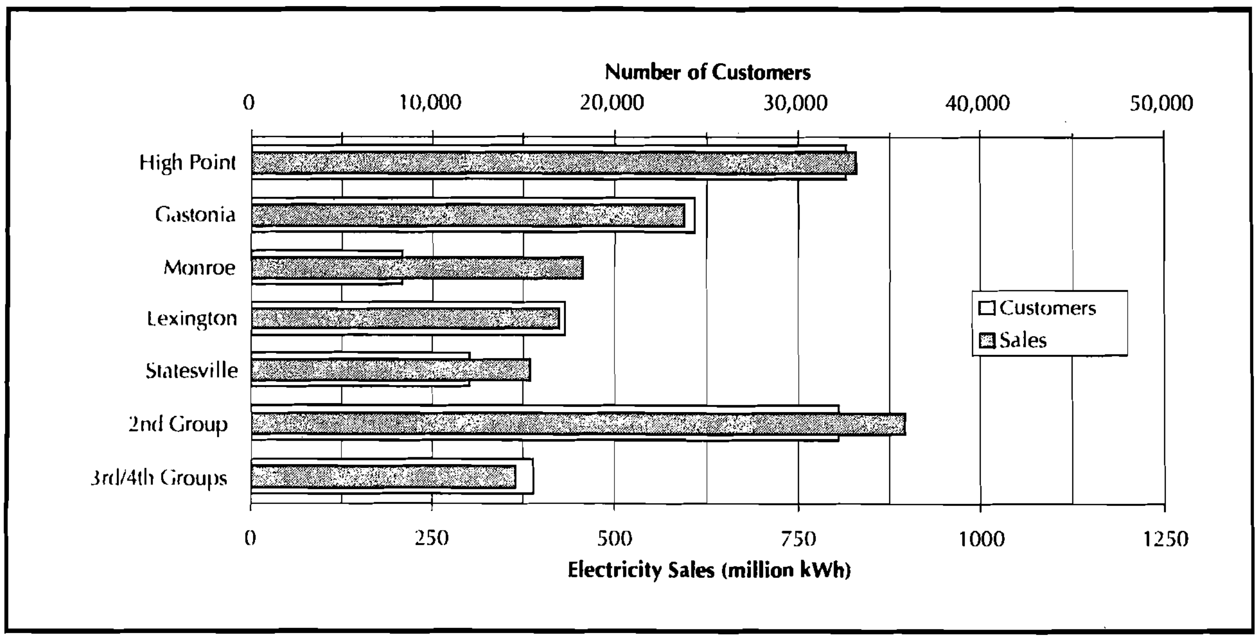


Figure 3-4. Total Number of Customers and Electricity Sales for NCMPA1 Cities



split away and built their own bulk power delivery facilities. Currently, they purchase power from Virginia Power. The three cities that remained with Wilson have negotiated decreases in their bulk power rates, as has Winterville with the City of Greenville. The high cost of MPA power has eroded revenue from satellite cities and that situation is likely to worsen as member cities' rates increase.

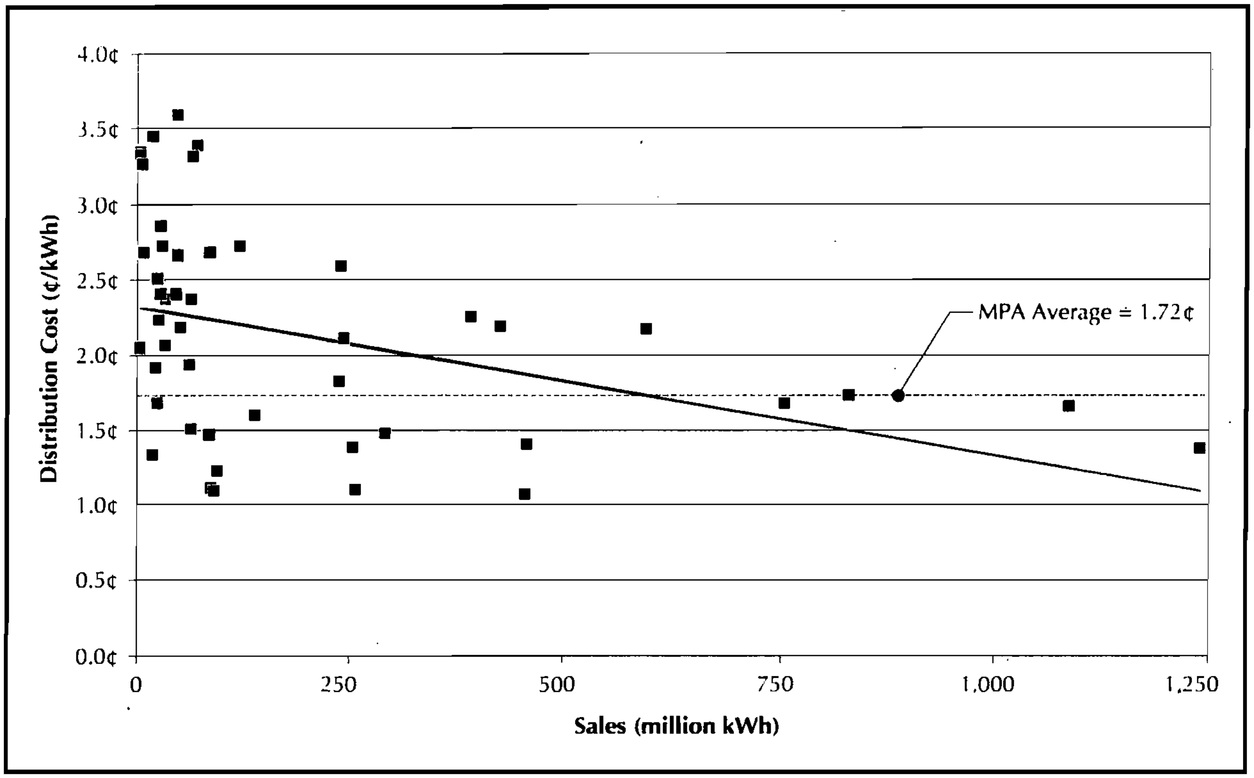
3.3 POWER DELIVERY COSTS

In 1998, the bulk power prices charged to the member cities by NCEMPA average about 6.9¢/kWh and about 5.1¢/kWh for NCMPA1.[1] These rates include both the generation and transmission components of cost. They compare to current rates of 4.5¢ for Duke Power, 5.1¢ for CP&L, 5.0¢ for North Carolina Power, and 5.7¢ for the North Carolina Electric Membership Corporation. The competitive open market price for bulk power is currently about 3.5¢/kWh. In percentage terms, bulk rates for NCEMPA range between 21 percent and 53 percent higher than for non-Agency suppliers in North Carolina, and bulk rates for NCMPA1 range from 7 percent to 35 percent higher. However, NCMPA1 has scheduled annual rate increases of 2.3 percent per year for the next decade, so its relative price advantage over NCEMPA is eroding (Figure 2-8). The price increases are necessary because NCMPA1's so-called Rate Stabilization Fund—essentially a source of funds to "buy down" their prices—is being rapidly depleted.

In addition to the generation and transmission components of cost, the third component of electricity supply costs is distribution costs. These are the main costs that each member city incurs for the construction, maintenance, management, and administration of the local distribution system. Figure 3-5 depicts those costs for all of the 51 member cities—each represented by one point in the figure. The purpose of this figure is to see whether small distribution systems are unusually expensive to operate.

[1]These prices represent the total revenue paid to the MPAs by their member cities divided by the total kWh that the member cities purchased from them.

Figure 3-5. Member Cities' Distribution Costs as a Function of Sales, 1997



The figure plots distribution costs per kWh of sales versus the total volume of annual sales. As shown, six of the seven largest systems have distribution costs below the overall average of 1.72¢/kWh. However, there is not much evidence for size-related cost savings among the small- to medium-sized systems. It does appear that some of the smallest systems incur the highest per-kWh costs, but some other small systems have nearly the lowest costs of all the member cities. Perhaps most striking is the extreme variation in these costs, ranging from as low as 1¢ to more than 3.5¢/kWh. These differences may be attributable to a number of factors that we have not investigated. The factors include customer mix (e.g., residential versus industrial); recent growth and consequently higher capital costs; differences in customer load factors; economies of scale (lower costs for larger systems); differences in quality of service (e.g., outage rates and repair response times); and differences in simple cost efficiency (e.g., staff and equipment costs). Therefore, without further investigation we cannot conclude anything about efficiency or service quality for the 51 member city systems. However, we can certainly conclude that by operating

independently they do not realize the advantage of cost averaging, causing some member city customers to pay distribution costs as much as 3 times higher than others.[2]

It is difficult to compare these member cities' distribution costs to those of other utilities based on the data available to us. For example, investor-owned utilities (IOUs) and electric cooperatives have a larger number of rural customers, which tends to increase their residential distribution costs per kWh compared to a municipal system. Nonetheless, based on data provided to us by the IOUs, we developed rough estimates of their average residential distribution costs ranging between 2.3 and 2.8¢/kWh—significantly higher than the member cities' average costs.

The distribution costs shown in Figure 3-5 include a cost factor that is incorporated into the rates charged by the member cities to retail customers. This is a controversial bill adder known as "transfers." Transfers are payments made from electricity revenues to a city's general fund. These transfers currently amount to about 0.3¢/kWh for NCEMPA cities and 0.4¢/kWh for NCMPA1 cities. The relative amount of transfers has been declining for the past 10 years, in part because of agreements with the Local Government Commission (LGC). Records on the amount of transfers for years prior to that were not available.

Although the transfers are controversial, there is some rationale for them. First, it is true that cities would realize some tax revenue if an IOU or electric cooperative owned the city's distribution system. In that case the other utility would pay property tax on the assessed value of the distribution system, and most of the associated property tax revenue would be paid to the city. Second, an IOU owner would require profits to be paid to its stockholders. Since municipal systems are government utilities they do not pay property taxes or earn profits. So two rationales for the transfers are that they substitute for a portion of property tax revenue that would otherwise be realized, and for profit margins that would be required by IOU owners.

In any case, most member cities are moving toward compliance with a policy set by the North Carolina LGC to promote more

[2]These distribution cost differences seem likely to account for part of the large differences in retail prices among member cities. See Appendix D of RTI's report to the Legislative Study Commission, *Task 2: Rate Comparisons*, July 1998.

efficient funding of city services. That policy limits transfers to the sum of two components: (1) 3 percent of the value of gross fixed assets and (2) documented city expenses associated with electric system operation to compensate the city for its investment in the electric system.

3.4 DEBT BURDEN

The member cities have taken on a huge debt burden through the MPAs. Figures 3-6 and 3-7 show both the aggregate amount of debt and the amount of debt service (principal and interest payments) for the cities that are members of NCEMPA and NCMPA1, respectively.

The scale for total debt is at the top of each figure, and the scale for debt service is at the bottom. The bars are identical in length because the assigned debt service costs per dollar of debt are identical for member cities in each MPA.

There is significant variation in the amount of debt per capita and per customer among the member cities, as shown in Figures 3-8 and 3-9. The overall averages of these amounts are also shown. The average debt per capita is about $9,300 for NCEMPA cities and about $7,600 for NCMPA1 cities. The corresponding averages for debt per customer are about $15,400 and $16,700. Across both agencies, the average debt per capita is about $8,500 and debt per customer is about $15,900. This variation could have important implications for the policy options to be considered in coping with the debt problem.

To consider the debt burden more carefully, we decided to examine the amount of debt per capita versus the total debt for each city. We had expected that the smallest cities would have the highest debt per capita. But that is not the case, as shown in Figure 3-10.

The vertical and horizontal lines labeled "median" in that figure are the median values for debt/capita and total debt, respectively. Any city above the horizontal median line has more debt per capita than at least half of all member cities, and cities to the right of the vertical median line have more total debt than at least half of all member cities. The numbering scheme and legend in the figure show where each of the 51 cities is positioned in terms of this relationship.

Figure 3-6. Total Debt and Debt Service for NCEMPA Cities

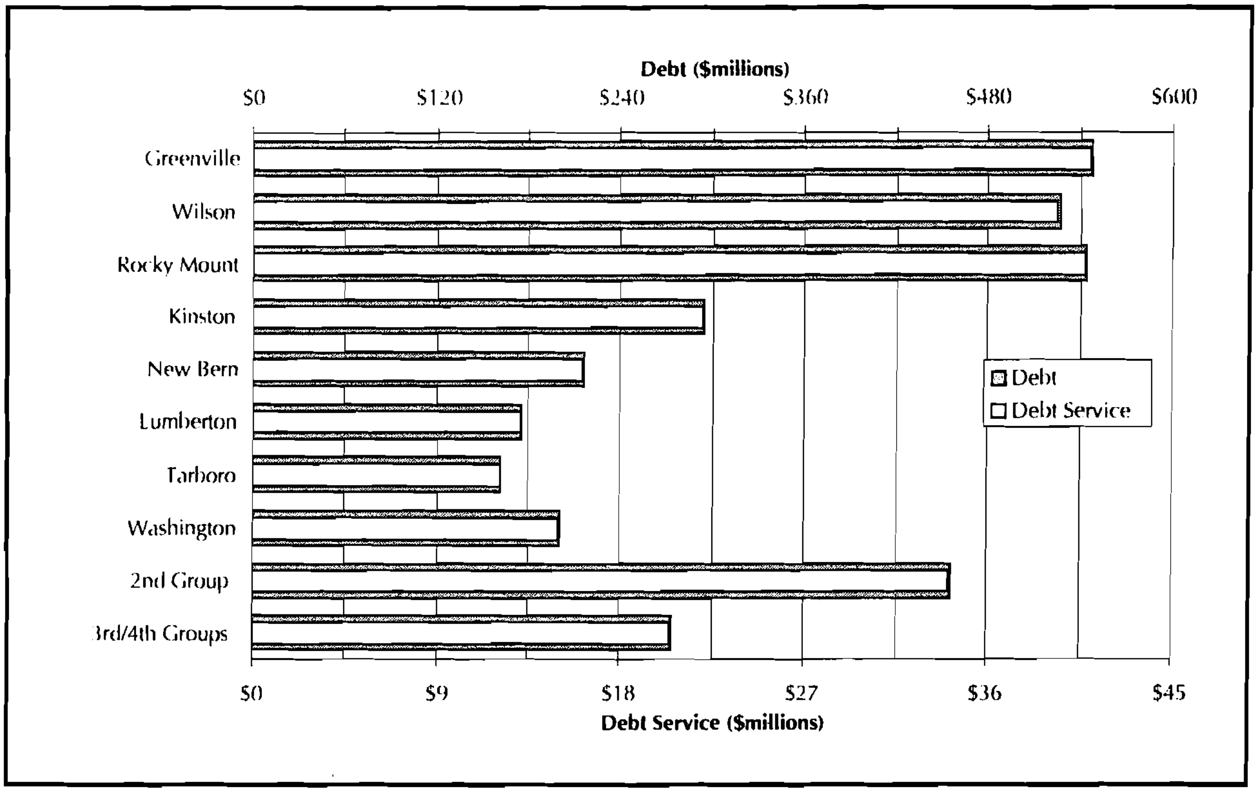


Figure 3-7. Total Debt and Debt Service for NCMPA1 Cities

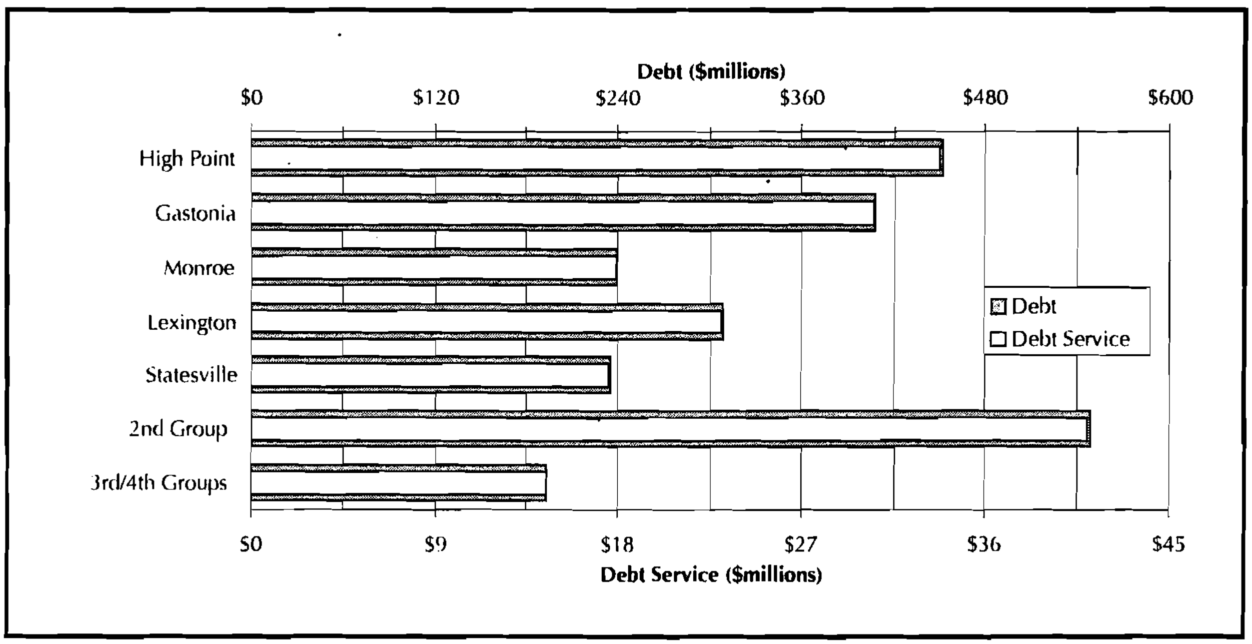


Figure 3-8. Debt per Capita and Debt per Customer for NCEMPA Cities

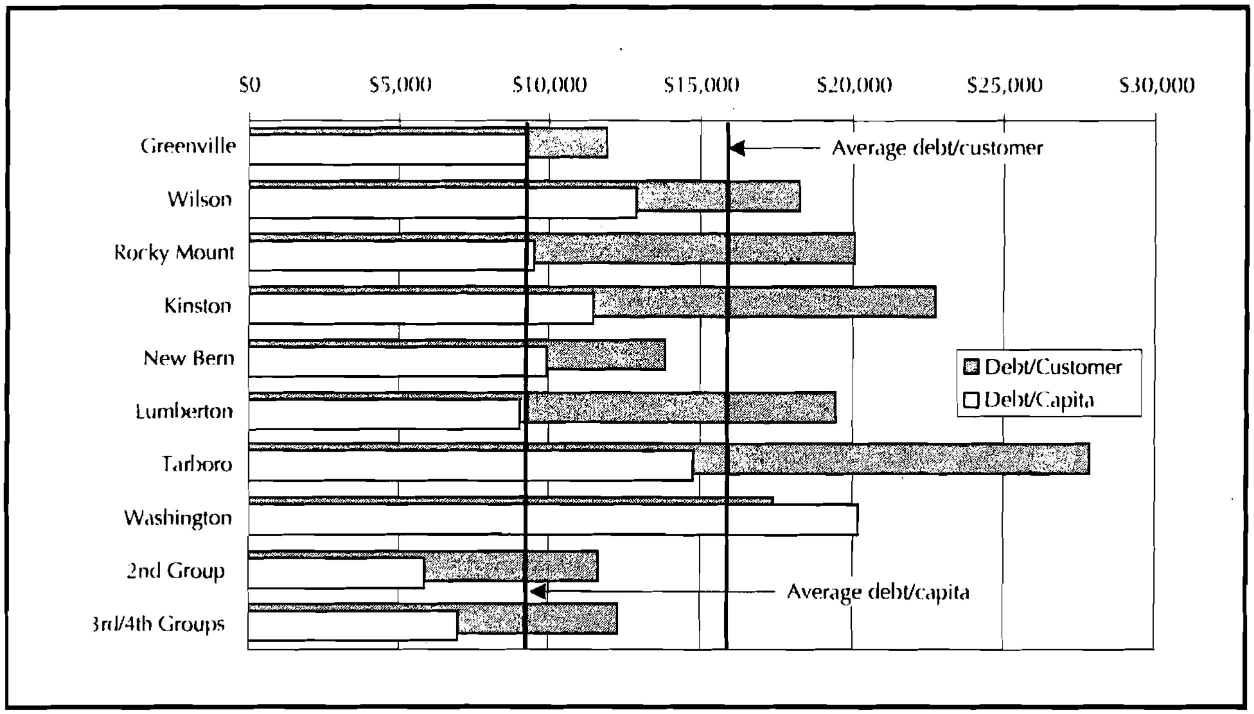


Figure 3-9. Debt per Capita and Debt per Customer for NCMPA1 Cities

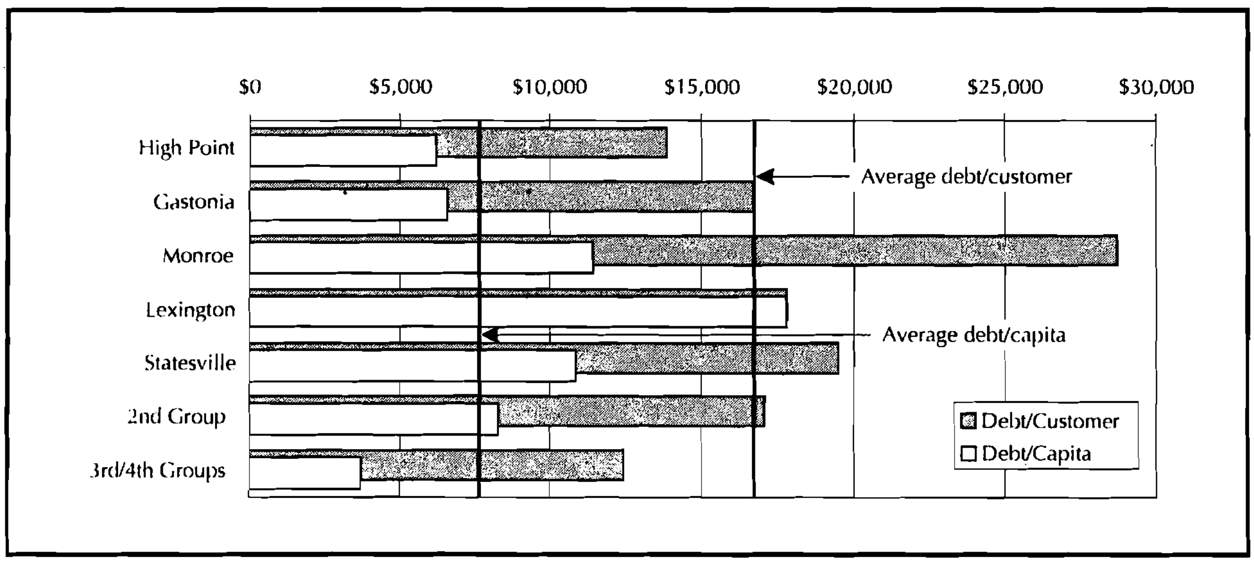
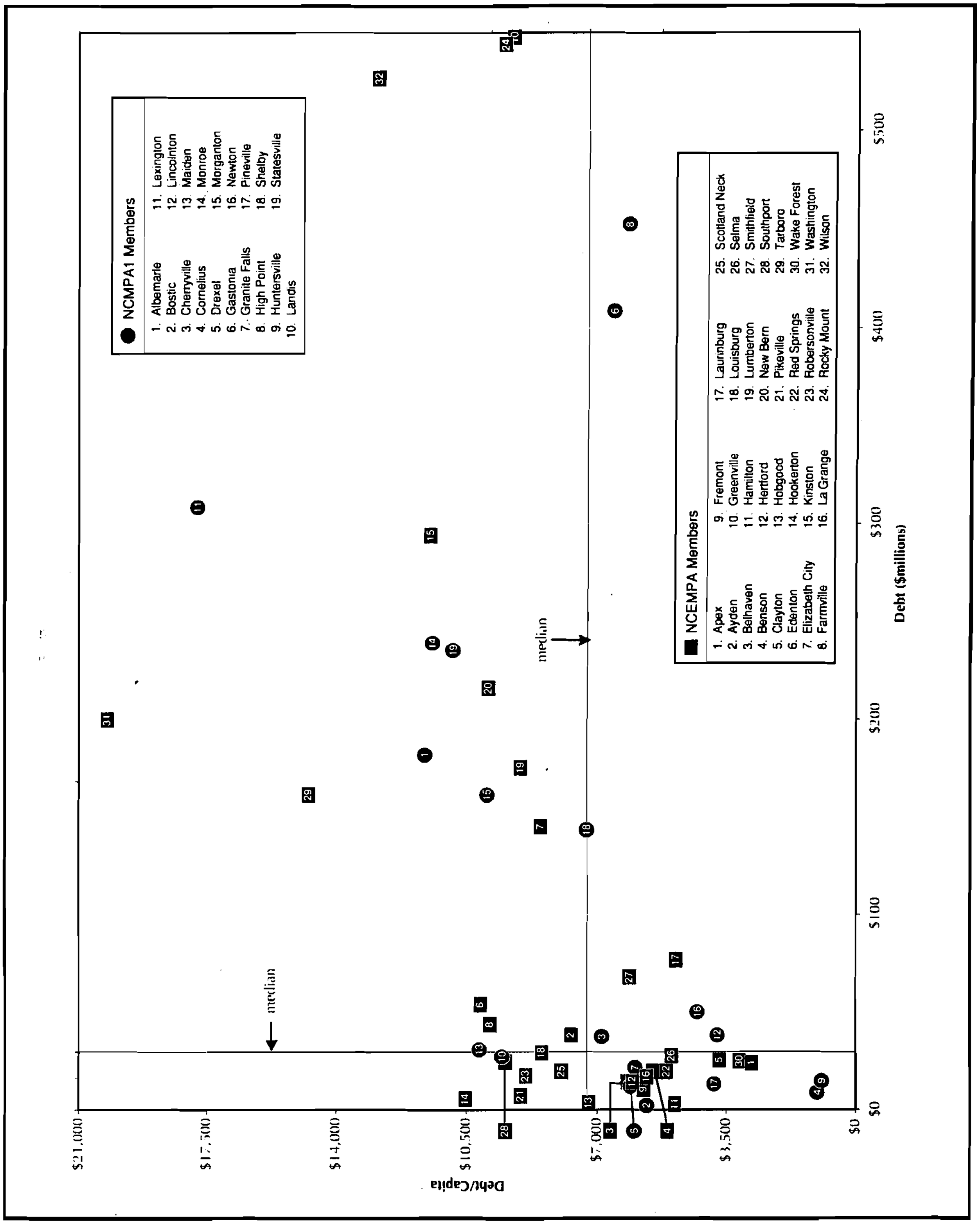


Figure 3-10. Amount of Debt per Capita versus the Total Debt



As it turns out, some of the larger cities are also the ones with the highest amount of debt per capita (e.g., Lexington, Wilson, Rocky Mount, Greenville, and New Bern), while the majority of the smaller cities have debt/capita ratios that are below the median. These patterns are probably due to the fact that larger cities have relatively higher industrial load. Since debt responsibility for member cities was set according to load, larger cities would have generally higher per capita debt responsibility. In any case, the overall debt burdens for the 51 member cities are abnormally high.

3.5 POTENTIAL MUNICIPAL REVENUE SOURCES

There is no easy solution to the debt problem that these cities face. However, we must explore any reasonable ways that they could raise funds to retire some of their debt.

One obvious municipal revenue source is additional property taxes. Such tax increases may or may not be accompanied by the issuance of municipal bonds, which could be serviced with the increased tax revenue. As shown in Figures 3-11 and 3-12, the property tax rates for the member cities are generally not far from the average for North Carolina municipalities. In fact, the average property tax rate for NCEMPA cities is above the state average, and the NCMPA1 cities are only slightly below. Nonetheless, the legal maximum for the property tax rate in North Carolina is $1.50 per $100 assessed value, so there is some opportunity for property tax increases. Even so, the amount of potential revenue from this source is modest. Each one-cent increase in the property tax rate for the 51 member cities would generate only about $2.8 million in annual revenue.

Another municipal revenue alternative would be for the cities to sell their distribution franchises. As detailed in Section 4, any such attempt has many legal ramifications with respect to the MPAs and their debt. Nonetheless, it may be useful to consider the potential value of those franchises. ElectriCities staff have reported that the total initial cost of all the member cities' distribution systems was approximately $750 million. The book value of those systems, i.e., their initial cost less depreciation, was about $420 million in 1997. However, the exclusive franchises and their customers also have value in the marketplace over and above the value of the

Figure 3-11. Property Tax Rates for NCEMPA Cities

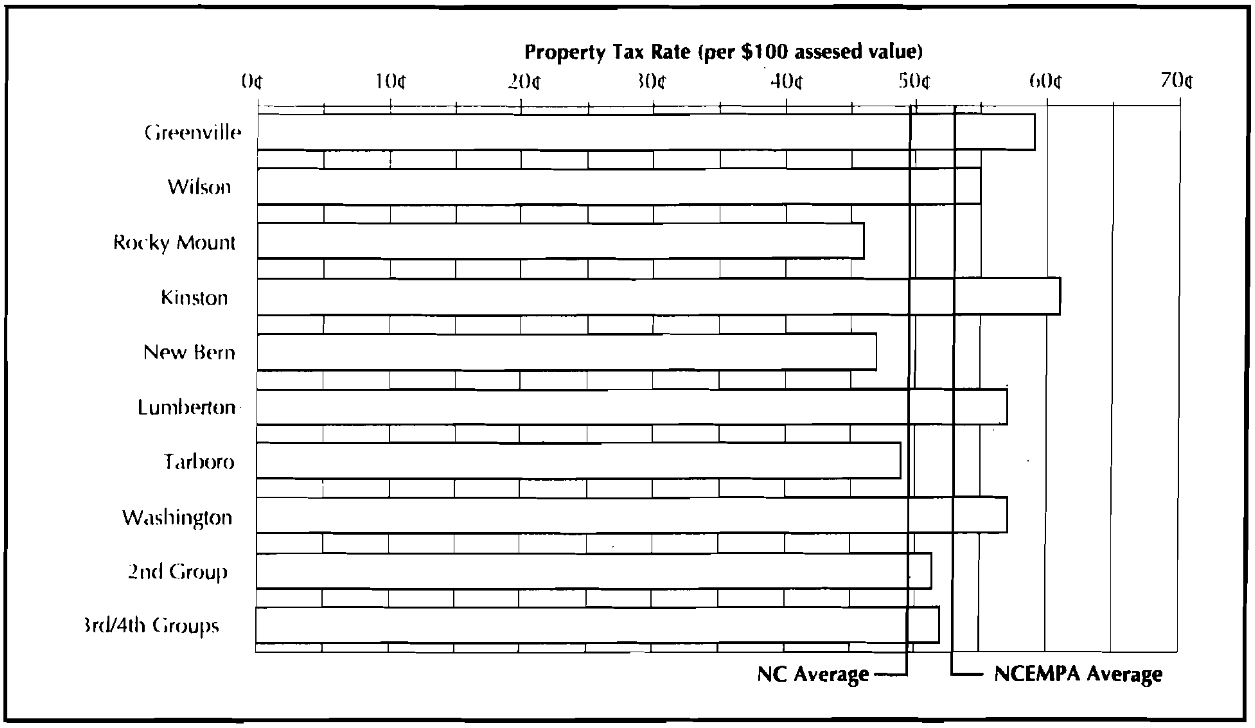
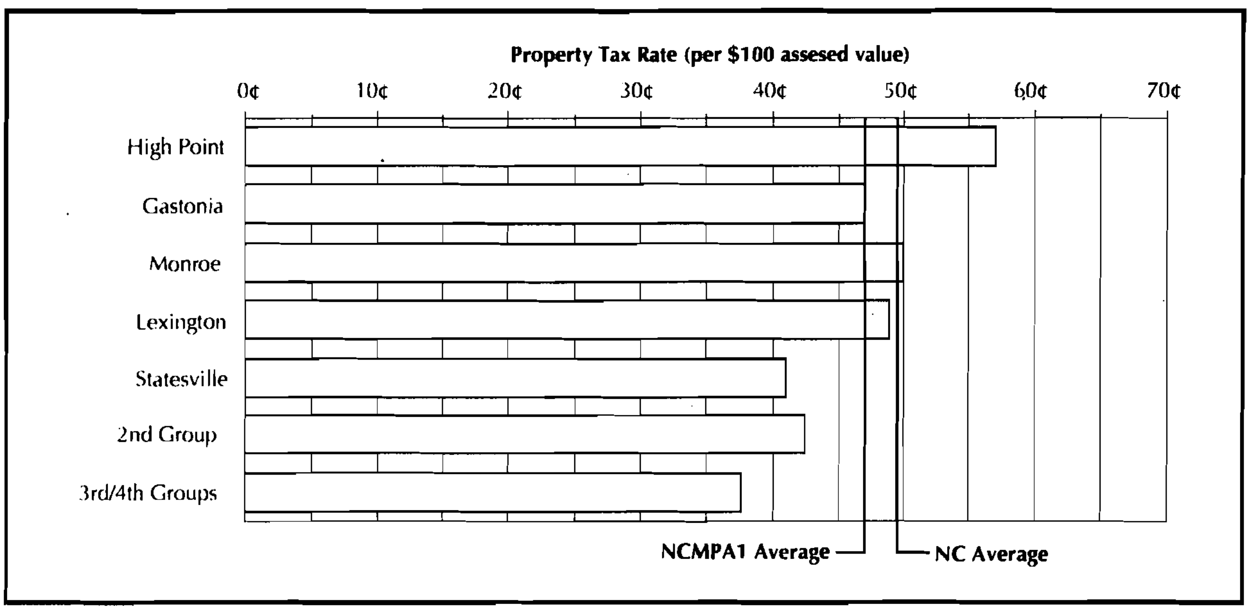
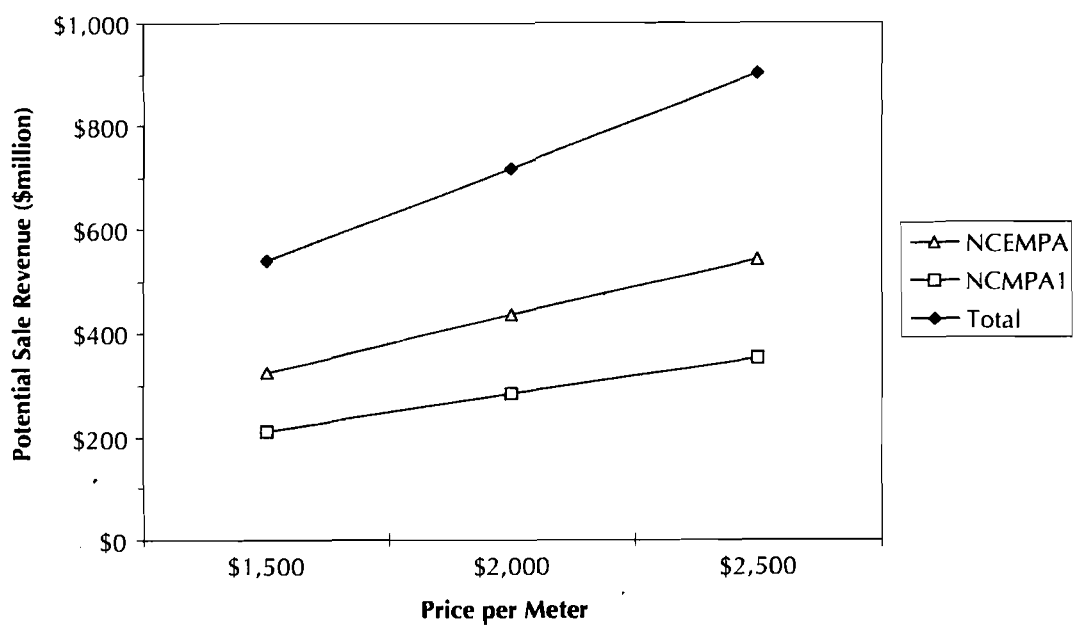


Figure 3-12. Property Tax Rates for NCMPA1 Cities



equipment. Furthermore, the book value of the equipment may undervalue the equipment itself. In Figure 3-13 we have plotted hypothetical values at alternative market valuations per meter. Although these valuations are based on the commonly mentioned assumptions about the value of municipal distribution systems, we cannot describe these valuations as rigorous or analytically based. Still these data provide "ballpark" estimates of how such systems might be valued if they were marketed.[3]

Figure 3-13. Potential Revenue from Sale of Municipal Systems



[3]We were unable to locate current data on the sale of distribution systems, although such data may exist. In any event, serious consideration of negotiated, as opposed to auction, sales methods would likely require a careful professional appraisal of the market value of each member city system.

4 Legal and Regulatory Environment

Any discussion of policy options for coping with the financial problems of North Carolina's municipal power agencies (MPAs) must consider a wide range of legal and regulatory factors. A number of organizations and individuals have both legal authority and obligations that will affect the feasibility and conditions of any policy changes. This section characterizes those legal positions for the predominant stakeholders—the state of North Carolina, the MPAs, the MPA member cities, the investor-owned utilities (IOUs) (Duke and Carolina Power & Light (CP&L)) most closely associated with the MPAs, and the bondholders. The following subsections summarize the salient authorities and obligations of each of these groups.

4.1 STATE OF NORTH CAROLINA

The state of North Carolina has the following legal authority and obligations that are of special significance to public power policies in North Carolina:

- The Electric Act, also referred to as the Territorial Assignment Act of 1965, authorized the state to designate territories eligible to be served by North Carolina electric suppliers. Specifically, customers being served by electricity providers in April 1965 were generally assigned as their customers, and all providers were prevented from adding utility customers by annexing part of one another's service territory. The Act also imposes "reasonable

limitations" on the authority of municipalities to extend electric service beyond their current borders.

- The Joint Municipal Electric Power and Energy Act (Chapter 159B), passed in 1975, determined that municipalities were important suppliers of electricity in North Carolina and that the state should allow municipalities to jointly finance, develop, own, and operate appropriate transmission and generation facilities. Subsequently, North Carolina municipalities received more authorization in 1977 when the citizens of North Carolina approved an amendment to the North Carolina constitution authorizing those joint actions by municipalities to be effected in concert with privately owned utilities.

- The Local Government Commission (LGC) of the state of North Carolina is responsible for the approval and sale of all the bonded indebtedness of all North Carolina units of local government (including the member cities) and the MPAs as well as nearly all public authorities. It is composed of nine members, including the State Treasurer, Secretary of State, State Auditor, and Secretary of Revenue as well as five other appointees. The LGC has broad authority to monitor the prudence, terms, rates, and conditions of all MPA debt.

- The LGC has the authority to monitor the member cities to ensure that they meet certain fiscal and accounting standards prescribed by the Local Government Budget Control Act. The Act, among other things, requires that the cities appropriate money to meet on-going contracts, such as the member cities' contracts with the MPAs.

- If a member city defaults on any payment of debt service on bonded debt, including payment of their share of the MPA debt service, the LGC has statutory authority to assume full control of the member city's financial affairs. Once the LGC exercises that authority, it is vested with all the powers of the member city's governing board. These powers include the expenditure of money, adoption of budgets, and other financial powers. In addition, under these circumstances, the LGC has the power to impose any electric rate increases necessary to ensure that the city meets it debt obligations.

- The state has sovereign authority over all regulated utilities and local government entities in North Carolina. Under certain conditions, that authority includes the power to order member cities to dispose of their distribution

franchises and to require North Carolina IOUs to acquire and operate power supply facilities.

- The North Carolina Utilities Commission (NCUC) has the authority to regulate any privately owned utility in the state of North Carolina, including any member city facilities that are sold to a private entity.
- The NCUC has the authority to approve or deny Certificates of Public Convenience and Necessity for new power generation facilities, including generation units proposed by the MPAs or their member cities.

4.2 MPAs

The North Carolina MPAs have significant legal authority and obligations that were largely determined at the time of their founding and were affected by many regulations governing public agencies and the issuance of tax-exempt bonds. The following are of special significance:

- The MPAs have authority to collect from each member city an appropriate share of "project power costs," defined as the sum of the total MPA debt service costs and the costs associated with operating plants owned by the MPA. The "appropriate shares" are defined as the initial project shares for each city.
- MPAs have the authority to acquire "supplemental power" (i.e., bulk power that is purchased to supplement power produced by capacity that they own). The North Carolina Eastern Municipal Power Agency (NCEMPA) and the North Carolina Municipal Power Agency 1 (NCMPA1) purchase supplemental power under "all requirements" (exclusive) contracts with CP&L and Duke Power, respectively. However, the MPAs can "opt out" of these contracts by providing advance notice—a minimum of 5 years to CP&L and 8 years to Duke Power.[1]
- MPAs also have the authority to sell any excess power produced by capacity that they own. This excess power has typically been sold back to Duke Power or CP&L under "sell-back" contracts.

[1] However, Duke Power and NCMPA1 agreed in 1997 to a special contract allowing NCMPA1 to give notice by the end of 1999 to bring supplemental power from another entity by June 1, 2001. This one-time option will expire if not exercised by NCMPA1 prior to the end of 1999.

- The MPAs are the "all-requirements" power suppliers to all the member cities, meaning that member cities cannot purchase electricity from any other suppliers or develop any additional supply capability of their own. However, there are some highly restrictive provisions that allow member cities to sell their shares of MPA assets subject to MPA consent. If a member city could execute such a sale it would then be free to purchase power from any source.
- The MPAs have the authority to set bulk power rate schedules that are applied "uniformly" to all member cities, not subject to the regulatory jurisdiction of either NCUC or the Federal Energy Regulatory Commission (FERC). The rate schedules are designed to recover the full amount of "project power" costs and "supplemental power" costs.
- A Board of Directors governs both the MPAs and ElectriCities and consists of a minimum of 14 members. The Board of Commissioners of each power agency elects six members, thus accounting for 12 of the 14 minimum. The remaining two members are elected by North Carolina members of ElectriCities who are not MPA members.
- The MPA must authorize any sale, lease, or encumbrance of any kind on the electric systems of its member cities.
- The MPAs are not allowed to sell any of their generation assets unless they "make provisions" to pay off all of the MPA debt. "Making provisions" would typically require actual payoffs or defeasance (i.e., the purchase of other financial assets whose payment schedules are sufficient to pay the debt service on bonds until they become callable or to maturity in the case of noncallable debt).

4.3 MEMBER CITIES

The cities that are members of the MPAs have the following legal authority and obligations that are of special significance to public power policies in North Carolina:

- Each member city has the authority, under North Carolina law, to acquire or build and operate the electric distribution system, which serves their city and its citizens. The service territory for each city is limited, as indicated above, by the 1965 Electric Act.
- Member cities, like other cities in North Carolina, are obligated to comply with the Local Government Budget and Fiscal Control Act. That act requires each member city to

operate without a budget deficit and to have its accounts audited annually by a properly certified and qualified organization.

- Each member city is obligated by its contract with the MPA to remit a minimum revenue amount each year. That amount is equal to its initial project share times the "project power" costs defined above. All its payments under the MPA bulk power rate schedule are credited to that total. Any shortfall must be supplemented by other payments in addition to bulk power bill payments.
- Member cities have full authority to set final retail electricity rates within their assigned service territory, not subject to the regulatory jurisdiction of either the NCUC or FERC. Rates must be set so as to recover the MPAs' bulk power costs and supplemental debt service costs. Member cities' rates also include distribution costs.
- Any member city may purchase the interest of another city that is party to the "Project Power Sales Agreement," subject to the approval of the MPA. Effectively this means that a member city may purchase the ownership, debt, and operating cost shares of another.
- A member city is not allowed to sell all or part of its distribution system if the sale will, in the opinion of the MPA, hinder its payments to the agency, or affects the tax-exempt nature of the MPA debt.
- If any member city defaults, the nondefaulting member cities are assigned an increased share of the MPA "project power costs," including both debt service and power supply operating costs. No nondefaulting member city is required to increase its share more that 25 percent above its "initial project share." The assignment of any default costs in excess of this 25 percent limit is unspecified.
- Any member city that defaults will, nonetheless, remain liable for the entire amount of the default, regardless of whether nondefaulting cities have acquired their shares.

4.4 IOUs

The three IOUs serving North Carolina include North Carolina Power, CP&L, and Duke Power. Because of their involvement in the sale of generation capacity, plant operation services, and bulk power to the MPAs, Duke Power and CP&L have legal authority

and obligations that are of special significance to public power policies in North Carolina:

- Both CP&L and Duke Power are responsible for the operation, maintenance, and fueling of the generating units that they own jointly with the MPAs and electric cooperatives and must dispatch power from all such units to serve the combined loads of the IOUs and the MPAs.
- Both Duke Power and CP&L have certain obligations under "take-or-pay" sell-back contracts. They must purchase specified percentages of the power produced by the generation capacity that is owned by their affiliated MPA; the contracts are complex and provide for variations from year to year.
- Both MPAs have multi-year bulk power contracts with IOUs for purchases of supplemental power supply.
- Duke Power has first right of refusal to purchase any part of NCMPA1's capacity at the Catawba plant (Restated Purchase, Construction, and Ownership Agreement, Article 17: Alienation and Assignment, Section 17.2, Par.(A) dated June 21, 1982). NCMPA1 may not sell, lease, or assign its ownership share of Catawba to another party without first allowing Duke Power to match the offer of the other party. If Duke does not match the offer of the other party, then the first right of refusal passes to North Carolina Electric Membership Corporation (NCEMC) and Saluda River Electric Membership Cooperative—another co-owner of Catawba—in that order.
- Under the Ownership Agreement between CP&L and NCEMPA, dated July 30, 1981, CP&L has **no** first right of refusal on NCEMPA's ownership in the Brunswick, Harris, Mayo, or Roxboro generation assets.[2]

4.5 BONDHOLDERS

Holders of MPA bonds have certain rights that are also of special significance to any resolution of the MPAs' financial problems:

- Many of the MPA bond issues are either noncallable or are callable only after a specified date in the future. The state or the MPAs could liquidate such bonds by purchasing them through financial markets, although not all

[2]Nonetheless, the Agreement contains other provisions that may complicate any sales effort.

bondholders may be willing to sell.[3] The only other way to "liquidate" such MPA debt is to provide for defeasance of it (i.e., to purchase other financial assets whose proceeds are sufficient to service bonds until they become callable or to maturity in the case of noncallable debt).

- The Joint Municipal Electric Power and Energy Act includes a covenant that the state of North Carolina will not impair the rights of bondholders to be paid or the ability of cities to earn the revenues needed to repay the bonds (G.S. 159B-22).

[3]Many bondholders may want to hold their bonds until maturity because the nontaxable interest earnings may be more attractive than available on comparable bonds currently for sale.

5 Policy Options

With a combined negative net worth in the billions of dollars, North Carolina's municipal power agencies (MPAs) are in difficult financial straits as they have been for a number of years. However, their problem is worsening, primarily due to the cumulative effects of debt growth. To cover all of their projected expenses under current contracts and organizational structures they will need to charge electricity rates that are extremely high—significantly above those projected for surrounding electric utilities.

This section discusses policy options that are available to the state of North Carolina and the affected stakeholders for coping with the MPA problem. Our approach is to describe the options at three levels of specificity. Section 5.1 outlines the general features of the four policy options that we identified. The first of the four options is assumed to be a continuation of current regulatory policies—we call that the Status Quo—so it is unique. The other three options are general enough that each could be defined in a very large number of versions, each incorporating different features, like different types of financing alternatives, such as those outlined in Section 5.1. Section 5.2 gets more specific by defining selected versions of each of the three policy alternatives for evaluation. Then, for each alternative, we provide a detailed list of advantages and disadvantages to each of the major stakeholders. Our purpose is only partly to critique those specific policy versions. An equally important purpose is to provide an analytical method and structure that policymakers can use to evaluate other policy variations that they may want to consider. Finally, Section 5.3 provides a quantitative evaluation of the specific policy alternatives detailed in

Section 5.2. There we consider hypothetical details on such policy features as electricity surcharge rates, asset sales, and financing options. The purpose of this quantification is, once again, to help evaluate those three specific policy options and to provide an analytical structure for evaluating future policy variations.

5.1 POLICY OPTIONS

The four policy options for coping with the MPA problem have different implications for the organizational control and ownership of the electric systems now controlled and owned by the MPAs and the member cities. We named the four options Status Quo, Debt Relief, Divestiture, and Dissolution, as described here.

Status Quo

The Status Quo option anticipates that the MPAs and member cities will continue to operate as they are now. This means that their member cities will be required to pay all costs in proportion to their designated shares of past investments made by the MPAs. The MPAs project that their generation costs will require charges to member cities at wholesale rates that will increase on average from 5¢ or 6¢/kWh up to 8¢ or 9¢/kWh within the next 15 years. (The wholesale rate on the bulk power market is currently about 3.5¢/kWh.) To cover their added costs for distribution, an average of 1.72¢/kWh, member cities would soon have to charge retail rates averaging 10¢ to 11¢ or more per kWh. As is the case now, some individual member cities will have to charge substantially more than that, perhaps as much as 16¢ or more per kWh.

Debt Relief

The Debt Relief option assumes that the MPAs retain some, but not necessarily full, control of their generation assets and that they remain the "all requirements" suppliers to their member cities. The member cities are assumed to retain their exclusive distribution franchises, perhaps under some restrictions. At the same time, this option assumes that the MPAs receive some external funding relief for their debt service costs. That funding relief can come from a number of possible sources.

Divestiture

The Divestiture option also requires debt relief as in the previous option. In addition, it would require that the MPAs sell or transfer the ownership and management of their generating assets. However, the MPAs would remain intact as the "all requirements" power suppliers to provide bulk power to their member cities; member cities would not have the option to choose alternative wholesale suppliers. Essentially, the MPAs would serve as aggregators of purchased power and as administrative clearinghouses. This is the kind of role the MPAs would be serving today had they chosen not to purchase or construct capacity. As mentioned in Section 3, the sale of their generating assets would require that the MPAs provide for full payment of all their debt.

Dissolution

The Dissolution option requires debt relief, the sale or transfer of all MPA generating assets, and the sale or transfer all of the MPAs' remaining assets and their dissolution as corporate entities. Again, the sale of MPA generating assets would require that provisions be made for full payment of all MPA debt.

This option *may* also require that member cities sell or transfer their distribution franchises and that their customers are transferred to the purchasing entity. Alternatively, under certain conditions, member cities may be allowed "to buy back" their franchises and may be left to negotiate their own bulk power purchases. If the member cities' distribution systems are sold (or leased) this option may also include some type of "job security" agreement covering the current employees of the municipal electric systems.

5.1.1 Potential Sources of Revenue

All of these four policy options will require revenue sources to pay the stranded MPA costs. Those sources include proceeds from any type of tax, asset lease or sale, bond issue, grants, or price concession that may be plausible. Table 5-1 provides a general summary of the most likely revenue sources that are detailed in the following list. We recognize that some of these sources may be unlikely due to political or legal constraints. However, we have provided the entire list for the sake of completeness.

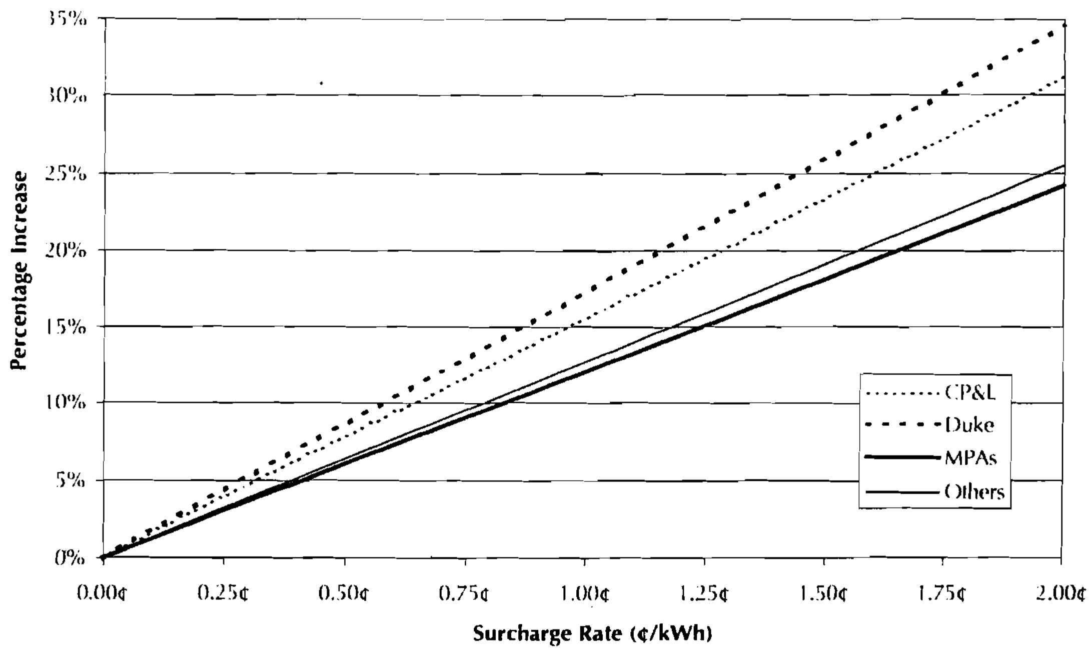
Table 5-1. Major Potential Sources of Revenue to Pay Stranded MPA Costs

Organization	Electricity Surcharges	Bond Issues	Propert y Taxes	Wire Charges	Incom e Taxes	Asset Sales/ Leases	Grants	Renegotiated Contracts
Electricity Suppliers								
MPAs						●		
Member cities	●	●	●	●		●		
Investor-owned utilities (IOUs)	●	●		●				●
Other North Carolina Suppliers	●			●				
State of North Carolina		●	●		●		●	
Federal Government					●		●	

➤ **Electricity Surcharges**: Electricity surcharges are charges that are added to retail electricity prices. A surcharge could be applied either as an ad valorem surcharge (e.g., 10 percent bill adder) or as a unit surcharge (e.g., 1¢/kWh). Such surcharges could be applied to all or to any subgroup of utility customers within the state. The surcharge rate may or may not be uniform for different customer groups or utilities. (For example, the surcharge for commercial and residential customers of Utility A could be different from each other. In addition the surcharge for customers of Utility A could be different from the surcharge for customers of Utility B. As detailed further in Section 5.1.2, some types of price freezes amount to nonuniform (or variable) surcharges of this type.)

Surcharges are often suggested, and are now being used in California, to retire state debt that was issued to "securitize" their stranded costs. In considering surcharges for North Carolina, it will be important to know how much "securitized debt" could be retired at various surcharge rates. For illustration, we assumed that North Carolina is able to borrow funds at the approximate current market rate of 4.15 percent on 5- and 10-year state-issued bonds of high quality. We also assumed that revenue from any surcharges would be used to repay this debt. Figure 5-1 shows projected percentage increases in electricity prices at hypothetical surcharge levels for each of four groups of power suppliers in North Carolina. For example, at a surcharge rate of 0.75¢/kWh the member cities' average

Figure 5-1. Percentage Increases over 1996 Retail Prices at Variable Surcharge Rates



price would increase by about 9 percent and the average price for Duke Power would increase by about 13 percent. Figure 5-2 shows the amount of debt that could be repaid by the end of a 5-year period during which all North Carolina electricity customers paid surcharges. For example, at a surcharge rate of 0.75¢/kWh revenue from Duke Power customers would repay about $1.75 billion of debt; Carolina Power & Light (CP&L) customers, about $1.14 billion; the MPA city customers, about $300 million; and other North Carolina electricity customers, about $560 million. The total debt repaid by a 0.75¢ surcharge would be about $3.75 billion, and the repayment shares for retail customers would be about 47 percent for Duke Power, 30 percent for CP&L, 16 percent for others, and 8 percent for the MPA cities.

Figure 5-3 provides a separate analysis for the MPAs. It shows how much debt could be repaid by the MPA cities alone under varying assumptions about both the surcharge rate and the number of years over which the surcharge is levied—the length of transition periods. For example, a surcharge rate of 3¢/kWh on member city sales would repay about $1.6 billion over a 7-year transition period and about $3.2 billion over a 15-year transition period.

Figure 5-2. Debt Repayment at Various Surcharge Rates: 5-Year Transition

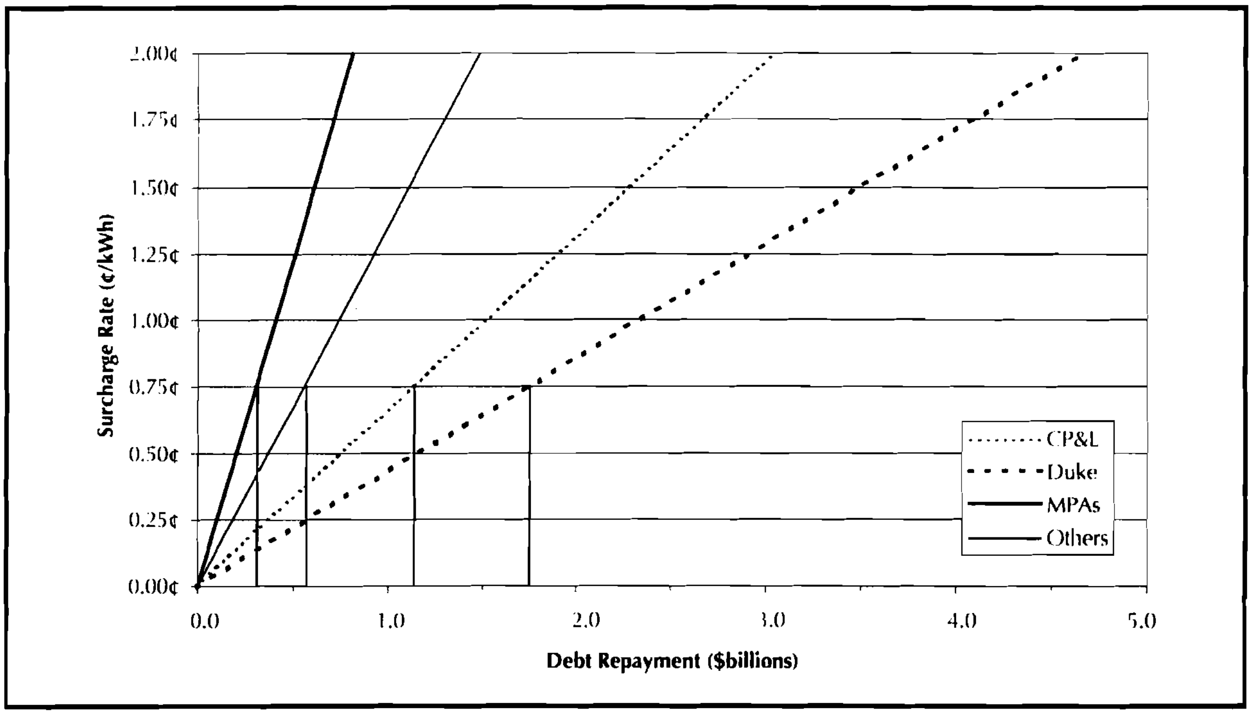
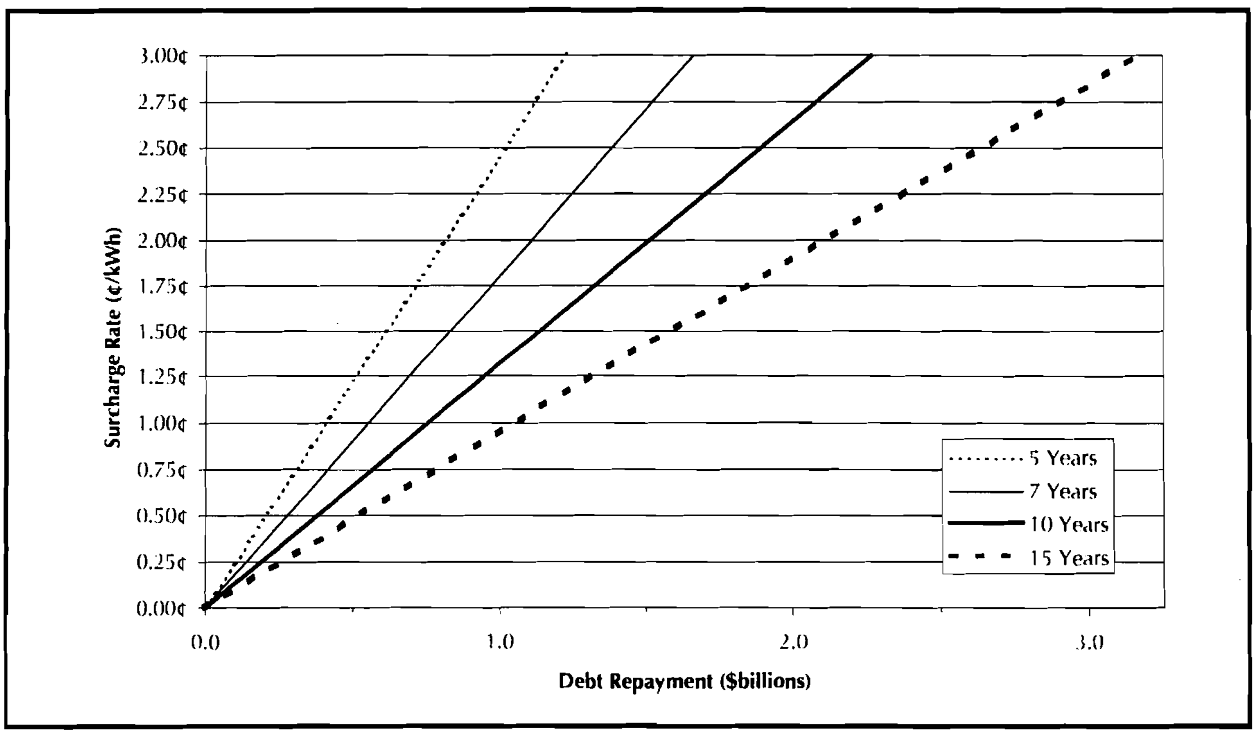


Figure 5-3. Debt Repayment at Variable Surcharge Rates: MPAs for Varied Transition Periods



- **Bond Issues:** MPA member cities could issue bonds whose proceeds are used to retire their share of MPA debt or pay their debt service costs. In addition, although it would require a statewide bond referendum, it is technically possible that North Carolina could issue general obligation bonds, backed by tax revenue from all North Carolina citizens. Revenue from the bond issue would be used to retire some or all of the MPA debt. Depending on how the bond issues are structured, they could possibly be tax-exempt, rather than taxable, type bonds.[1]

- **Property Taxes:** Property taxes are typically levied by counties and municipalities in North Carolina. One option is that the MPA member cities could raise property taxes and apply the revenue to retire or service their share of the MPA debt. However, as indicated in Section 3.5, the revenue potential from this source is quite limited.

  Although the legal issues are unclear, it may also be possible for the state to levy a property tax surcharge on only the electric utility property in North Carolina. For example, electric utilities now pay about $100 million per year in property taxes to the counties and cities of the state. A property tax surcharge could be levied on all electric utility property or, for example, only on transmission facilities. The value of transmission facilities has arguably risen the most in this era of wholesale competition and may rise further if retail competition is implemented. All the revenue could be diverted to retire or service the MPA debt.

- **Wires Charges:** The term "wires charges" often refers to surcharges on transmission services—e.g., volumetric charges per unit of electric energy transmitted. In other words, instead of putting an explicit electricity surcharge on the retail customer's bill, the state might place a wires charge on transmission services and require the owners of transmission facilities to remit the proceeds to the state. The "wires charges" would ultimately have a price impact that is similar to a simple surcharge but would be administered differently.

[1] Any proposed tax-exempt financing transaction or series of transactions that provides direct or indirect benefits to a nongovernmental entity raises federal tax issues under the so-called "private use restrictions." If the benefits are deemed to be for purposes not permitted by the Internal Revenue Code, the bonds will be classified as "private-activity" bonds and the interest will be taxable for federal income tax purposes. Some of the succeeding sections of this report assume the availability of tax-exempt financing, which would clearly have to meet these Internal Revenue Service (IRS) standards.

- **Income Taxes:** Income taxes represent another source of potential revenue to relieve the MPA debt burden. The main sources are corporate and individual income taxes at both the state and federal level. The most obvious options are simply to raise the income tax rates for corporate or individual taxpayers and use the revenue to pay the MPA debt burden. Legislation and possibly a voter referendum would be required to authorize such a use of tax revenues.

  Another option is for the state to offer state income tax credits to organizations that are required to assume some responsibility for part of the MPA debt service costs. The most obvious organizations are the IOUs that pay about $100 million in North Carolina income taxes each year. The North Carolina Utilities Commission (NCUC) would most likely have the authority to direct IOUs to apply any such tax credits payments to the payment of MPA debt.

  In addition, there may be some potential for federal tax deductions in connection with payments for stranded costs. For example, under the price freeze options proposed by ElectriCities (Section 5.1.2), IOU payments into a state-administered stranded cost recovery fund may be valid income tax deductions for the IOUs. In addition, effective federal and state support could be gained by issuing tax-exempt bonds to securitize stranded costs.

- **Asset Sales:** Sales of both MPA and member city assets represent another source of funds to pay the MPA debt. As indicated in Section 2, the MPAs hold about $1.7 billion in financial assets that could be liquidated under certain circumstances.[2] In addition, the MPAs' generating capacity and other property assets could be sold. Finally, the member cities could sell their complete distribution systems, including the exclusive business franchises and all the tangible assets. All such sales would be subject to the legal and regulatory constraints detailed in Section 4.

  Sales of both generation and distribution assets could be effected with an "open auction" of some sort or through a "negotiated sale" among the joint owners. In any case, the "asset package" could be "bundled" or "unbundled." For

[2]In this report we have not addressed a number of issues regarding the actual liquidity and availability of these invested funds. For example, the Trust for Decommissioning Costs would likely have to be sold to any buyer of MPA nuclear capacity; the bond interest and principal accounts must be used to pay current liabilities; and Rate Stabilization Funds are being steadily depleted to reduce retail rates. Our analysis does not address the details of these liquidity issues. We leave that for future studies of more detailed policy options.

example, all of the generation assets of both MPAs could be bundled together and bidders could make offers on the whole package or on individual units within the package. Similarly, all the 51 municipal distribution franchises could be bundled to comprise a single "utility" serving about 9 percent of the electricity load in North Carolina. Bidders could be required to bid on the whole bundle or may be allowed to bid on certain components or bundles of components.

- **Asset Leases:** Leasing generation and distribution assets is another alternative although they may offer limited potential for much added revenue. As is the case with asset sales, all such leases would be subject to the legal and regulatory constraints detailed in Section 4. For example, with MPA consent, an MPA member city may be able to lease its electric system to another member city or to a private company, while maintaining ownership and regulatory oversight. The member city would repay its debt. The generation capacity could also be leased. Like the asset sales options, both types of lease deals could be struck through either an "open auction" or "negotiated sale" and could be "bundled" or "unbundled" packages of assets. In addition the lease agreements could be structured to require that the rates charged by the operator are tied to the CP&L and Duke Power rate schedules. The agreements could even require identical rate schedules, with the exception that member city customers would be subject to certain negotiated surcharge rates above those rates. See Section 5.2 for further discussion of this approach.

- **Grants:** Another option is for the state or federal government to make outright grants to retire or service the MPA debt. This option is an unlikely prospect. However, there has been some recent discussion of federal assistance to isolated electric membership cooperatives with nuclear plant cost problems. Thus, it remains a possibility as a means of retiring a portion of the MPA debt.

- **Renegotiated Contracts:** The MPAs have bulk power purchase and sell-back contracts with both Duke and CP&L. Renegotiation of those contracts to reduce the cost of purchased power or increase the revenue from excess power sales would obviously provide additional revenue for MPA debt service.

5.1.2 Policy Variations

Each of the policy alternatives mentioned above can be designed with many variations. The following list summarizes a few of those variations:

- **MPA Governance:** The debt relief option as described above provides the MPAs and their member cities with some major concessions and no substantial quid pro quo. One option for addressing that is to require that the Board of Directors for the MPAs include significant representation by the other entities in North Carolina who are required to assume a significant part of the MPAs' debt burden. For example, officials of the Local Government Commission (LGC), all the major IOUs in North Carolina, and electric cooperatives may have seats on the Board.

- **Price Freezes:** An alternative (or even complement) to surcharges may be to impose price freezes for the member cities. Those freezes would remain in effect for a specified period after retail competition begins. A disadvantage of this approach is that it could create even larger disparities between IOUs' and member cities' prices, since IOU prices may decline after competition begins. A fixed "premium surcharge" on member city customers, as discussed in Section 5.3, is an alternative to this type of price freeze and ensures more stability of the price differentials between the retail rates between the IOUs and member cities.

  Two other types of price freezes could be considered,[3] but both are similar to a uniform statewide surcharge in determining who pays for the stranded costs accumulated by the MPAs.[4] Both types would freeze the electricity rates of all electricity suppliers in North Carolina for a period of 5 years, for example. Under the first type of price freeze, some authority, such as the NCUC, would calculate the **difference between the frozen prices and the competitive market price of power** for all North Carolina electricity suppliers. The competitive market price would be determined as the sum of each supplier's distribution costs and the reported market price for delivered bulk power in North Carolina. That difference would be multiplied by each supplier's kWh sales to calculate a required

[3] It is possible that the following two types of price freezes could lead to legal disputes among various affected electricity providers depending on the method used to direct IOU contributions to any stranded cost recovery pool.

[4] Though not described in this much detail, ElectriCities has recently advocated these types of price freezes in its "Electric Utility Restructuring Brief," February 1999.

contribution to a statewide stranded cost pool. (The details of this process could be somewhat complicated for the electric membership cooperatives and independent, that is, non-MPA, municipal systems in North Carolina.) In any case, to have any meaningful effect in coping with the MPA debt problem, the concept would require that the statewide stranded cost pool be used to retire all stranded costs in the state in proportion to each supplier's actual stranded costs. So this idea could logically be called a **statewide variable surcharge,** where the surcharge varies by electric supplier and is equal to the difference between the competitive price and their current price. Thus, it is similar to the statewide uniform surcharge in the way it acquires statewide contributions to resolve the MPA problem. It is different from the uniform surcharge in that MPA customers would be paying the same premium prices, compared to IOU customers, that they are paying today.

The second of the alternative types of price freeze would work in the same way, except that an external authority would calculate the **difference between the frozen prices and the costs of power** for all North Carolina electricity suppliers. But, once again, these differences multiplied by kWh sales would be the required contributions to a statewide stranded cost pool. This approach would almost certainly lead to rate cases for the purpose of cost—and hence variable surcharge—determination, likely involving considerable delay and dissention. In addition, it is unclear how the process would work for the electric membership cooperatives and the independent municipal systems in North Carolina.

➤ **Regulatory Assets:** Generation and distribution assets may be sold to North Carolina utilities at prices that are unquestionably above market (considering all concessions related to financing, liability take-backs, etc.). In that case, it would be conceivable that the state could negotiate consideration of these premiums as part of the IOUs' stranded cost that would be recovered if and when retail competition begins. As long as the current regulatory process remains in place, they would be a part of the IOUs' rate bases.

➤ **Notice of Competition Timeline/Rate Cases:** The state, perhaps through the NCUC, could serve official notice to Duke, CP&L, and North Carolina Power stating that

✓ the state may at its discretion declare that retail competition in generation services will begin on or after a specified date (e.g., 2004);

- ✓ the state will not allow recovery of stranded costs after the onset of retail competition; and
- ✓ the IOUs have a limited time period, perhaps 6 months, within which to file a rate case to adjust their retail rates to recover all of their anticipated stranded costs prior to the onset of competition.

Those new retail rates would recover stranded costs between the time the new rates go into effect and the date that retail competition begins. This option obviously requires the recovery of stranded costs before, rather than after, competition begins.

The state may choose to offer two or more flexible options as part of this policy. The first may be to allow some negotiation, as part of the rate case determinations, regarding the earliest date by which competition could begin. The second is to leave open the possibility of electricity surcharges to be levied after competition begins. If required, those surcharges could be determined in a subsequent rate case to be filed at the onset of competition and would reflect actual market experiences in recovering stranded costs during the interim. This option would be particularly relevant if the state were to implement the Divestiture or Dissolution options at asset prices that are unquestionably above market.

- ➤ **Alternative Asset Purchase Option:** If the assets of the member cities and the MPAs are sold through negotiated agreements, it may be reasonable to consider selling the distribution systems located within the service territory boundaries of the North Carolina Power Company system to that company for reasons of economy in service delivery. Some asset sales to electric cooperatives might be considered on the same basis. It may also be possible under certain scenarios to allow member cities to retain control of their distribution systems. That might be contingent on the cities' payment of amounts that are "equivalent" to benefits that the state would realize if they were sold.

- ➤ **Nullification of Power Sales Contracts:** Under certain scenarios discussed below in Section 5.2.3, the affected parties may agree to nullify the bulk power sales contracts between the MPAs and the IOUs.

- ➤ **North Carolina Tax Credits:** North Carolina corporate income tax credits could also be used to enhance the attractiveness of deals for the purchase of either generating or distribution assets.

- **North Carolina Liability Assumption:** The state could retain any uninsured liability associated with the future decommissioning and decontamination of the nuclear power capacity now owned by the MPAs.[5]

- **Employment Security:** If the assets of the member cities and MPAs are sold, it may be reasonable to require some type of employment security for their current staff.

- **Member City "Opt Out" Provisions:** Any policy that includes the sale of member cities' electric systems might include an "opt out" provision for individual cities. These provisions would presumably specify the level and timing of debt repayment as well as other legal obligations of any city making that choice.

5.2 SPECIFIC POLICY VERSIONS

This section discusses a specific version of each of the four policy options. We first describe in some detail the characteristics of each policy option and then discuss the advantages and disadvantages of that option for the key stakeholders. We have identified the following organizations and individuals as the key stakeholders:

- member cities,
- MPAs,
- IOUs,
- electric cooperatives and other electric suppliers,
- the state of North Carolina,
- MPA bondholders, and
- the federal government.

When discussing advantages and disadvantages of each option, we interpret each of these entities to represent both the organization and all of the individuals they serve or employ. For example, the state of North Carolina represents the state government and all citizens of the state; the member cities represent their citizens, their

[5]Presumably the utility that purchases the ownership shares in MPA plants would also purchase the Trust for Decommissioning Costs. Lawyers for the state of North Carolina and the buyer would have to construct a binding agreement that requires payment by the state of ultimate cleanup costs exceeding the sum available from the Trust fund balances and any contributions that may become available from federal or other sources.

ratepayers, the distribution system, and its employees; the utilities represent the company employees, shareholders, and ratepayers; and so on.[6]

5.2.1 Status Quo

Unlike the other three policy alternatives, there is, by definition, only one version of the Status Quo.[7] It simply means that nothing would be done by the state to address the problems of the MPAs. Under this option, the agencies and member cities will be left to find their own solutions. The following lists summarize the advantages and disadvantages of that approach for each of the stakeholder groups.

Member Cities/MPAs

Advantage

1. The MPAs and member city distribution franchises would be left intact and allowed to continue setting their own rates and policies without external regulatory oversight.

Disadvantages

1. Member cities will have to continue charging electricity prices that are 25 percent or more above the rates of surrounding utilities.
2. Regardless of whether retail competition occurs, the rate disparity between the member cities and surrounding utilities will increase. However, the disparity would likely be greater under retail competition.
3. All rate disparities will have the effects of reducing the relative attractiveness of the member cities' service territories as locations for new commercial and industrial growth and lowering the value of properties within their

[6]We recognize that, in some cases, the interests of ratepayers and employees may not be the same as the companies' or municipalities' interests. However, we have attempted to distinguish those situations in our discussions of advantages and disadvantages. Extensive future analyses may more thoroughly address the effects of these policy changes on the structure of electricity markets and the potential market power of electricity providers. Such work is likely to require separate analysis for ratepayers, employees, taxpayers, and other classifications of stakeholders.

[7]Current electricity rates for North Carolina IOUs have been in effect for 5 to 10 years. The last rate case decisions by the NCUC were rendered for CP&L in 1988, Duke Power in 1991, and North Carolina Power in 1993. So most North Carolina electricity customers have effectively experienced price freezes for several years.

service territories. However, new plants may continue to locate just outside their service territories to obtain lower rates from the surrounding utilities, still providing economic opportunity to citizens of the member cities.

4. The rate disparities will perpetuate the incentive for the MPAs, their member cities, and large customers to install their own generating units, distribution facilities, and electricity conservation technologies that may be fundamentally uneconomic. They may be uneconomic in the sense that far fewer investments of that type would be installed if electricity were available at competitive market prices.
5. The level of electricity prices required to service the debt could force financially weak member cities with extremely high debt burdens to default on their share of debt service payments. This would require that the LGC take over the financial affairs of the defaulting cities.

IOUs

Advantages

1. This policy avoids other solutions to the MPA problems, which could be costly to the IOUs and their customers.
2. The Status Quo will tend to perpetuate the differences between IOU and member cities' rates, thereby making it relatively easier for the IOUs to recruit new businesses from outside the state and existing businesses from member cities' service areas.
3. It allows the IOUs to continue realizing profits associated with their sale of bulk power and plant operating services to the MPAs.

Disadvantages

This policy seems unlikely to cause significant disadvantages for IOUs in North Carolina.

Electric Cooperatives and Other Electric Suppliers

Advantage

1. This policy avoids other solutions to the MPA problems, which could be costly to other North Carolina utilities and their customers.

Disadvantages

This policy seems unlikely to cause significant disadvantages for electric cooperatives and other North Carolina electric suppliers.

State of North Carolina

Advantages

1. This policy averts the complex legislation, referendums, organizational changes, and other costly transition processes associated with all of the other policy options.
2. Some constituents argue that this policy is the fairest, in the sense that the member cities were and are independent business decisionmakers. As such they are viewed as having made fully informed business decisions in the normal business context of uncertainty, and, therefore, should be responsible for the consequences of those decisions.

Disadvantages

1. Persistence of significant rate disparities between the member cities and other locations in North Carolina may distort incentives for local economic growth and development. To the extent that electricity rate differences in the range of 25 to 35 percent significantly affect new plant locations and expansions, the member cities will tend to lose some economic growth within their electricity service areas, although growth could still occur in adjoining areas.
2. The high electricity rate differentials under this policy are likely to cause persistence of other "boundary effects," such as utility investments in "excessive" or duplicative distribution facilities to serve certain customer locations at the service territory boundaries.
3. The state of North Carolina may have more difficulty recruiting new commercial facilities to the extent that prospective new companies are leery of the "ElectriCities problem." Their uncertainty about resolution of this problem may hamper recruitment efforts.
4. The LGC will be required to take over the financial affairs of any member cities that default on their share of MPA debt service costs.
5. If any city defaults on its share of MPA debt service, the bond rating agencies could downgrade North Carolina debt issues, increasing the cost of borrowing for the state.

Bondholders

Advantage

1. Assuming that all debt service payments are made, bondholders will likely avoid any early recalls and any administrative inconvenience associated with refinancing the MPA debt.

Disadvantage

1. Because it appears that the state of North Carolina currently has the ultimate responsibility for ensuring MPA debt service payments, the risk of default on MPA bonds would seem very small. However, this policy option seems more likely to cause bond defaults than any other option because the other options ensure more direct backing by the state of North Carolina.

Federal Government

The Status Quo option seems unlikely to have any effects that would cause advantages or disadvantages for the federal government.

5.2.2 Debt Relief

Section 5.1.1 details potential sources of revenue. Each source or possible combination of sources suggests a specific policy option. For example, one policy might involve a certain type of electricity surcharge combined with payments generated from new bond issues and/or property taxes. In other words, there are many policy options within the category of debt relief. That is also true of the two remaining policy options, both of which involve asset sales.

This analysis focuses on one of those many debt relief options—the one proposed by ElectriCities and known as the "uniform surcharge" proposal. ElectriCities has not fully detailed their proposal. However, the basic idea is that the stranded costs of all North Carolina electric utilities would be combined into a single pool to compute a uniform surcharge to be applied to all electricity sales in North Carolina during a 5-year transition period after the onset of retail competition.

Quite recently ElectriCities appears to have withdrawn their uniform surcharge proposal and replaced it with a price freeze proposal for debt relief. Their new proposal is along the lines of

the price freezes described in Section 5.1.2, and, as indicated there, is essentially a statewide variable surcharge.[8] Therefore, most of the following advantages and disadvantages apply equally well to their price freeze plan.

Member Cities/MPAs

Advantages

1. This policy would effectively shift most of the MPAs' and member cities' debt burden to the customers of other North Carolina utilities.
2. The cost shifting allows the MPAs and cities to price their electricity sales at levels that are relatively close to projected prices under retail competition. Thus, the policy would allow them to stay in business in a competitive market environment.
3. The member cities may sell more electricity when prices are lowered, possibly allowing them to lower their average distribution costs and, hence, further lower their electricity rates.
4. Any lowering of electricity prices will allow member cities to become more competitive with other electricity suppliers. Although there is much debate and uncertainty about the precise influence of electricity prices on firms' location decisions, there is no serious doubt about the directional effect. Clearly, when all other locational characteristics are the same, any rational firm or household will prefer the location that offers lower rates.
5. Some residential and commercial properties are served by member cities that charge in excess (in some cases much in excess) of 10¢/kWh. Yet their neighbors outside the member city's service territory may pay in the range of 6 or 7¢/kWh. If property buyers are rational and could have purchased otherwise similar properties in either location, they will have taken this cost difference into account. That would have tended to lower property values within the member city's service territory, although this effect is not likely (as yet) to be very large. Nonetheless, the debt relief option could slightly increase property values in member cities.

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[8] The new ElectriCities proposal is described in "Electric Utility Restructuring Brief," ElectriCities of North Carolina, Inc., February 1999. Their proposal sounds similar to the second or third type of price freeze mentioned in Section 5.1.2.

Disadvantages

This policy seems unlikely to cause significant disadvantages for the MPAs or member cities.

IOUs

Advantages[9]

1. This policy allows the IOUs to realize any future profits associated with the sale of bulk power and plant operating services to the MPAs.
2. This policy resolves stranded costs for all utilities in the state and allows for full recovery of those costs.

Disadvantages

1. IOU customers would be required to pay higher prices than would otherwise be the case if their surcharges were utility-specific, reducing the availability of those funds for other uses.
2. Any increase in prices caused by the uniform surcharge may reduce electricity demand by IOU customers and may, therefore, cause lower use of power supply facilities and lower profits, depending on capacity availability during the period that the surcharges are applied.

Electric Cooperatives and Other Electric Suppliers

Advantages

1. This policy seems unlikely to cause any advantages for electric cooperatives and other North Carolina electric suppliers.
2. This policy resolves stranded costs for all utilities in the state and allows for full recovery of those costs.

Disadvantages

1. Customers of electric cooperatives and other North Carolina electric suppliers may be required to pay higher prices, reducing the availability of those funds for other uses.
2. Any increase in prices caused by the uniform surcharge may reduce electricity demand by their customers and may

[9]Other debt relief options, such as North Carolina taxpayer financing or surcharges on only MPA cities' customers combined with some other state sources of funding, would avoid surcharges on IOU customers. Consequently, under those plans IOUs would avoid loss of sales and profits due to the price effects of a surcharge.

cause lower use of power supply facilities and raise per-kWh distribution costs.

State of North Carolina

Advantages

1. A uniform surcharge is simple and easy to administer, so it avoids many of the financing, legislative, and organizational complexities of some other options.
2. A uniform surcharge would tend to reduce differences in electricity rates within the state. Therefore, local economic development in North Carolina will not be significantly affected by large rate disparities from one locale to another.
3. This option eliminates the possibility that member cities will default on their debt service shares and become subjected to financial control by the LGC (i.e., the state of North Carolina).

Disadvantage

1. This policy would cause higher rates for some utilities, e.g., North Carolina Power, that had little or no association with the MPAs' problems. Obviously, this outcome raises some negative political issues.

Bondholders

Advantage

1. This policy will tend to increase the likelihood of prompt and full payment of all debt service obligations compared to the Status Quo.

Disadvantages

This policy seems unlikely to cause significant disadvantages for bondholders.

Federal Government

Advantages

The debt relief option seems unlikely to cause significant advantages for the federal government.

Disadvantage

1. A uniform surcharge will likely decrease the sales revenues and profits of the IOUs, thus reducing federal corporate income tax revenue. It would also tend to decrease

corporate income taxes from other North Carolina entities for which electricity costs represent a deductible expense.

5.2.3 Divestiture

As mentioned above this policy option would require that the MPAs sell or transfer the ownership and management of their generating assets, and it allows them to remain intact as the "all requirements" power suppliers to provide bulk power to their member cities. The specific plan outlined here is subject to a host of permutations, as described broadly in Section 5.1. If this scenario is of interest to the Study Commission, then it should be refined and re-examined in more detail. The divestiture plan scenario would include the following features:

1. The state takes over all the assets and liabilities of the MPAs after putting contracts in place that require certain actions, as specified below, on the part of North Carolina IOUs and MPA member cities.
2. The state relieves member cities of any future burden associated with MPA debt *except* that cities are required to levy a surcharge on their customers during a specified transition period. That surcharge must be set at a level that is sufficient to service the residual of MPA debt that remains after the sale of generation and liquidation of the MPAs' financial assets.
3. The state liquidates or provides for defeasance of the MPA debt to the extent possible using the invested funds held by the MPAs.
4. The state issues bonds to liquidate or provide for defeasance of all or part of the remaining MPA debt. Possibly surcharge revenue and loan repayments from asset buyers would provide sufficient revenue to secure state revenue bonds (as opposed to general obligation bonds).
5. The state negotiates deals to resell the generation assets of each MPA to their IOU co-investors in generation facilities. The deal packages are structured to be much more attractive to the IOU co-owners than some policy alternatives that the state could impose (e.g., surcharging IOU customers to recover the MPAs' stranded costs). The main features of the deal packages include:

   - ✓ The state transfers title to all capital and fuel and other assets classified as Electric Utility Plant along with the Trust for Decommissioning Costs to the purchasing

IOU. The purchaser is responsible for making continuing payments into the Trust.

- ✓ The state retains any uninsured future liabilities associated with the eventual decommissioning and decontamination of the nuclear capacity previously owned by the MPAs.
- ✓ The state provides 100 percent debt financing to the purchasing IOUs for the purchase of all generation and related assets.[10] Financing is offered at a preferred rate of interest, perhaps as low as the state's borrowing rate.
- ✓ Purchasing IOUs release the MPAs from all their bulk power purchase contracts.
- ✓ The state *may or may not* offer future North Carolina corporate income tax credits to the purchasing IOUs.
- ✓ The state *may or may not* serve notice of a timeline for retail competition and a deadline for rate case filings. The rate case would be filed by the IOUs to recover stranded costs prior to the onset of competition. The state *may or may not* include with this notice a requirement that the IOUs finance these asset purchases themselves instead of receiving state financing. (See Section 5.1 for more discussion of this option.)

6. MPAs are required to purchase bulk power in the competitive wholesale market following the Federal Energy Regulatory Commission (FERC) Order 888.
7. The state repays the securitized debt with revenue it receives from the MPA surcharges and from the payments that the IOUs make on their capacity purchases.

Member Cities/MPAs

Advantages

1. Member cities gain independence and autonomy to pursue their own suppliers as wholesale customers through their aggregator—the MPA that no longer owns generation. But all member cities remain "full requirements" customers of the MPAs.
2. Member cities gain relief from part of their MPA debt.

[10]We are not advocating 100 percent debt financing, but we incorporate this assumption for convenience in this discussion and the quantitative analysis discussed in Section 5.3.

3. Member cities are likely to gain immediate rate relief even after adding surcharge payments (as long as the surcharges amount to less than projected debt service costs). This avoids perpetuation of rate inequality that is almost certain under the Status Quo.
4. Member cities avoid perverse incentives to invest in generating capacity and in distributed generation (customer-owned) capacity that is currently encouraged by a bulk rate structure that incorporates debt payments (i.e., this policy eliminates incentives for uneconomic bypass).
5. This option equalizes rates paid by member cities after the transition period and puts them on equal footing for economic development.

Disadvantages

1. Member cities are required to pay surcharges over and above the wholesale rates they pay to their MPAs during the transition period specified by the settlement. This may perpetuate existing disparities between member cities' rates and those of surrounding IOUs.
2. Member cities lose their ownership in generation facilities.

IOUs

Advantages

1. IOUs acquire substantially increased shares in the generation facilities that they already operate and jointly own with the MPAs, thereby increasing their control.
2. IOUs avoid future liabilities associated with the eventual decontamination and decommissioning of the share of the generation facilities currently owned by the MPAs.
3. IOUs avoid future negotiation and transactions costs associated with the operations of jointly owned generating units.
4. IOUs acquire 100 percent debt financing of generation purchases at a preferential rate of interest.
5. IOUs avoid alternative ways of resolving the "ElectriCities problem" that could be more expensive to the IOUs and result in less control of the underlying resources.

Disadvantages

1. Even after tax credits, concessionary financing, and avoidance of future liabilities for decommissioning and decontamination, the purchase price for generation may be

higher than the market price of baseload capacity alternatives.

2. The IOUs could lose some future profits associated with bulk power sales and plant operating services contracts with the MPAs.

Electric Cooperatives and Other Electric Suppliers

Advantages

1. Non-MPA municipal electric suppliers in North Carolina avoid having to assume part of the costs associated with solving the MPA problem.
2. Electric cooperatives in North Carolina are not burdened further beyond the significant costs they must already incur to cope with their debts associated with nuclear plant purchases.

Disadvantages

This policy seems unlikely to cause significant disadvantages for other North Carolina utilities.

State of North Carolina

Advantages

1. This option ultimately will tend to equalize rates between member cities and the surrounding service territories of the IOUs, and, therefore, improve the prospects for economic development that is founded on underlying resource endowments rather than historic quirks in power supply investments.
2. None of the stakeholders would be entirely happy with this approach, because all are required to shoulder part of the costs, so this approach is more politically balanced than some of the alternatives.
3. The ElectriCities/MPA problem is resolved before any final determination regarding implementation of retail competition. By addressing the problem immediately the state avoids complications that would result from the implementation of retail competition prior to addressing the MPA problem.
4. This option eliminates the possibility that member cities will default on their debt service shares and become subjected to financial control by the LGC (i.e., the state of North Carolina).

Disadvantages

1. The state is required to assume unknown future liabilities for decommissioning and decontamination.
2. The state will "lose" net tax revenue if it grants tax credits to the IOUs. This will require the state to impose other taxes to make up lost revenues or cope with a smaller budget surplus.

Bondholders

Advantage

1. Bondholders will be assured of receiving full payment because the state of North Carolina will have assumed responsibility for the MPA debt.

Disadvantages

1. Some bonds may be called at the earliest possible date, reducing the period during which bondholders receive higher interest payments than are available on competing bonds.
2. There may be some paperwork inconveniences due to shifting payment responsibilities among North Carolina state agencies.

Federal Government

Advantages

1. Federal taxpayers may benefit because another government entity (the state of North Carolina) will have assumed some uninsured decontamination and decommissioning liability that might otherwise fall in part to the federal government.
2. Federal income tax payments should increase because a taxable private utility would have taken over a nontaxable entity. We would expect this even though the purchaser of the MPA generation could deduct all normal associated costs, including interest payments and depreciation.

Disadvantages

This policy seems unlikely to cause significant disadvantages for federal taxpayers.

5.2.4 Dissolution

Another option is to completely dissolve the MPAs and transfer ownership and operation of the member cities' distribution systems

in a way that ensures reliable service from an alternate supplier. The specific plan outlined here is subject to a host of permutations, as described broadly in Section 5.1. If this scenario is of interest to the Study Commission, then it should be refined and re-examined in more detail. The dissolution plan scenario would include the following features:

1. The state takes over all the assets and liabilities of the MPAs after putting contracts in place that require certain actions, as specified below, on the part of North Carolina IOUs and MPA member cities.
2. The state assumes full control of MPA debts and assets assigned to all MPA member cities and simultaneously acquires unencumbered title to each city's complete municipal electric distribution system and business.[11]
3. The state liquidates or provides for defeasance of MPA debt to the extent possible using the invested funds held by the MPAs.
4. The state issues bonds to liquidate or provide for defeasance of all or part of the remaining MPA debt. Possibly surcharge revenue and loan repayments from asset buyers would provide sufficient revenue to secure state revenue bonds (as opposed to general obligation bonds).
5. The state negotiates deals to resell the municipal system franchises and generation assets of each MPA to their IOU co-investors in generation facilities. The deal packages are structured to be much more attractive to the IOU co-owners than some policy alternatives that the state could impose (e.g., surcharging their customers to recover the MPAs' stranded costs). The main features of the deal packages could include the following:
   - ✓ The state transfers title to all capital and fuel and other assets classified as Electric Utility Plant along with the Trust for Decommissioning Costs to the purchasing IOU.
   - ✓ The state retains any uninsured future liabilities associated with the eventual decommissioning and decontamination of the nuclear capacity previously owned by the MPAs.

[11]The actual legal transfer of ownership to the state, as opposed to direct transfer to the buyer, may not be required. If this option were chosen, parties to the transaction would obviously need to complete a substantial amount of legal work to resolve such details.

- ✓ The state transfers to the purchasing IOU the title to all member cities' municipal electric systems within its service territory, including perpetual rights to the municipal service franchises.[12]
- ✓ The state provides 100 percent debt financing to the purchasing IOUs for the purchase of all generation assets as well as the distribution assets and municipal service franchises.[13] Financing is offered at a preferred rate of interest, perhaps as low as the state's borrowing rate.
- ✓ The state *may* offer future North Carolina corporate income tax credits to the purchasing IOUs at a level that is required to effect the sale to the IOU.
- ✓ The state *may or may not* serve notice of a timeline for retail competition and a deadline for rate case filings. The rate case would be filed by the IOUs to recover stranded costs prior to the onset of competition. The state *may or may not* include with this notice a requirement that the IOUs finance these asset purchases themselves instead of receiving state financing. (See Section 5.1 for more discussion of this option.)

6. The state requires that all municipal system customers immediately become customers of the purchasing IOU and pay regulated electricity rates that are identical to existing IOU customers. Therefore, all municipal systems absorbed into the IOUs' service territories will immediately fall under the jurisdiction of NCUC, as components of the IOUs' expanded systems.
7. The IOUs are required to levy a surcharge on their customers located within the former service territories of the member cities. This surcharge must be levied during a specified transition period at an amount that is sufficient to service the residual of MPA debt that remains after the sale of MPA generation assets, the liquidation of the MPAs' financial assets, and the sale of the distribution systems.

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[12]Even if the cost of these purchases to the IOUs are unquestionably above market value, the "excess cost" should not become part of the stranded costs caused by competition in generation services. The reason is that their total acquisition costs would become part of the regulated rate base for their distribution systems. The IOUs would then recover those costs through changes in regulated charges for distribution services. The resulting average distribution costs would apply uniformly over all CP&L and current NCEMPA customers, and over all Duke Power and current NCMPA1 customers.

[13]We are not advocating 100 percent debt financing, but we incorporate this assumption for convenience in this discussion and the quantitative analysis discussed in Section 5.3.

8. The state repays the securitized debt with revenue it receives from the MPA surcharges and from the payments that the IOUs make on their capacity and distribution system purchases.

Member Cities/MPAs

Advantages

1. Member cities gain relief from their share of MPA debt.
2. Member cities are likely to gain rate relief, compared to their projected rates under the Status Quo, even after adding surcharge payments. The perpetuation of rate inequality that is almost certain under the Status Quo is avoided.
3. Current customers of the member city electric systems gain regulatory oversight of their electric supplier by NCUC, and rate disparities among current member cities would be eliminated. (See Item 6 under Disadvantages.)
4. Member cities avoid future transactions costs involved in negotiating with satellite cities.
5. Member cities avoid perverse incentives to invest in peaking capacity and in customers' on-site capacity due to the bulk rate structure that incorporates debt payments (i.e., this policy eliminates incentives for uneconomic bypass).
6. Member cities gain property and other tax revenues from the buyers of their electric systems.
7. This option equalizes rates paid by member cities after the transition period and puts them on equal footing for economic development.
8. This option allows the member cities and MPAs to avoid any lopsided negotiating situations with the IOU co-owners of plants and bulk power providers.

Disadvantages

1. Member cities lose control of their municipal power systems, possibly resulting in the loss of jobs.
2. Member cities relinquish their ownership in generation facilities.
3. Member cities lose access to "transfer funds" from electricity revenues that are available to support other municipal services. (However, transfers have been declining rapidly anyway, although they still exist.)

4. Member cities will lose independence and autonomy to pursue their own bulk power suppliers.
5. This option destroys the financial underpinnings for ElectriCities because the member cities dominate that organization—they account for 90 percent of ElectriCities' revenue. Thus, at least in its current form, the ElectriCities service organization is susceptible to dissolution as well.
6. Member city customers may need to pay surcharges for a limited time period that would maintain some rate disparity between member cities and surrounding IOUs.

IOUs

Advantages

1. IOUs acquire substantially increased shares in the generation facilities that they already operate and jointly own with the MPAs, thereby increasing their control.
2. IOUs will now own but will avoid future liabilities associated with the eventual decontamination and decommissioning of the share of the generation facilities currently owned by the MPAs.
3. IOUs acquire additional retail service franchises that are currently surrounded by their service territories and, therefore, have an opportunity to create a more economic power supply system for all customers combined and future opportunities to market new services.
4. Because the member city electric systems offer higher geographic density of customers, IOUs should have an opportunity to lower their average distribution costs.
5. IOUs avoid future negotiation and transactions costs associated with the operations of jointly owned generating units.
6. IOUs acquire 100 percent debt financing of both generation and distribution system purchases at a preferential rate of interest.
7. IOUs avoid alternative ways of resolving the "ElectriCities problem" that could be more expensive to the IOUs and result in less control of the underlying resources.

Disadvantages

1. Even after tax credits, concessionary financing, and avoidance of future liabilities for decommissioning and decontamination, the purchase price for the generation and

distribution systems and distribution franchises may be higher than baseload capacity alternatives.

2. The distribution systems/franchises acquired through these purchases will require some transition investment to ensure the same type and quality of service received by other IOU customers.
3. The IOUs could lose some future profits associated with bulk power sales and plant operating services contracts with the MPAs.

Electric Cooperatives and Other Electric Suppliers

Advantages

1. Non-MPA municipal electric suppliers in North Carolina avoid having to assume part of the costs associated with solving the MPA problem.
2. Electric cooperatives in North Carolina are not burdened further beyond the significant costs they must already incur to cope with their debts associated with nuclear plant purchases.

Disadvantage

1. This option allows the surrounding IOUs even more control that could reduce electric membership cooperatives' and independent cities' bargaining power with the IOUs on bulk power purchases, transmission, and other power supply issues.

State of North Carolina

Advantages

1. This option eliminates the possibility that member cities will default on their debt service shares and become subjected to financial control by the LGC (i.e., the state of North Carolina).
2. This option equalizes rates within the service territories of the IOUs and therefore improves the prospects for economic development that is founded on underlying resource quality rather than historic quirks in power supply investments.
3. The ElectriCities/MPA problem is resolved before any final determination regarding implementation of retail competition. By addressing the problem immediately the state avoids complications that would result from the

implementation of retail competition prior to addressing the MPA problem.

4. None of the stakeholders would be entirely happy with this approach, because all are required to shoulder part of the costs, so this approach is more politically balanced than some of the alternatives.

Disadvantages

1. The state is required to assume unknown future liabilities for decommissioning and decontamination.
2. The state will "lose" net tax revenue if it grants tax credits to the IOUs. This will require the state to impose other taxes to make up lost revenues or cope with a smaller budget surplus.
3. NCUC regulation of the IOUs leaves open the possibility that they may file a rate case that could be partly based on the costs of their acquisition of the additional generation and distribution assets and customers. The result could be a rate increase affecting all IOU customers.

Bondholders

Advantage

1. Bondholders will be assured of receiving full payment because the state of North Carolina will have assumed responsibility for the MPA debt.

Disadvantages

1. Some bonds may be called at the earliest possible date, reducing the period during which bondholders receive higher interest payments than are available on competing bonds.
2. There may be negligible paperwork inconveniences due to shifting payment responsibilities among North Carolina state agencies.

Federal Government

Advantages

1. Federal income tax payments should increase because a taxable private utility would have taken over a nontaxable entity. We would expect this even though the purchaser of the MPA generation could deduct all normal associated costs, including interest payments and depreciation.

2. Federal taxpayers may benefit because another government entity (the state of North Carolina) will have assumed some uninsured decontamination and decommissioning liability that might otherwise fall in part to the federal government.

Disadvantage

1. Loss of income tax revenue due to interest payment write-offs by IOUs on debt-financed buyout of MPAs and remaining depreciation charges on the MPA electric utility plant may result.

5.3 IMPLEMENTATION SCENARIOS

In this section, we provide some quantitative insights on possible implementation of the specific policy variations discussed in Section 5.2. We have sought to identify reasonable—but obviously hypothetical—surcharge rates, transition periods, asset sales prices, and other policy variables. Using these parameter values, we have projected financial outcomes for the stakeholders affected by the MPA problem. Once again, the specific plans outlined here are subject to many permutations, as described broadly in Section 5.1. If any of these scenarios are of interest to the Study Commission, then they should be refined and re-examined in more detail.

5.3.1 Debt Relief Scenario

The specific Debt Relief scenario that we identified in Section 5.2.2 is the statewide uniform surcharge proposed by ElectriCities. For this analysis, we assume a **hypothetical** present value of stranded costs for the MPAs of $3 billion.[14] Our goal here is to determine the surcharge rate that will generate a present value equal to that amount. In computing the present value, we assumed a discount rate of 4.15 percent, which is the approximate current rate for a tax-exempt security with a 10-year maturity.

Our calculations assume that all North Carolina electricity customers will be required to pay the surcharge. The necessary surcharge rate is approximately 0.6¢ if applied for 5 years, 0.32¢ for 7 years, and 0.22¢ for 10 years. The share of the MPA debt that

[14]The forthcoming Volume 3 of this report will provide our detailed stranded cost estimates. It will also demonstrate the extreme sensitivity of those estimates to many assumptions, especially the sensitivity to forecasted competitive prices for bulk power.

would be paid by MPA customers under this plan would be about 8 percent. The share paid by other companies varies somewhat with the length of the recovery period (see Figure 5-2 for a 5-year period). Roughly, Duke Power Company customers would pay about 47 percent; CP&L customers, about 30 percent; and others about 15 percent.

Similar calculations could be developed for the statewide variable surcharge rates that are implied by one of the price freeze options (see Section 5.1.2). That option would require contributions to a stranded cost pool (variable surcharges) for each utility where the contributions are equal to the difference between a calculated competitive price for power and their current rates.

5.3.2 Divestiture Scenario

The Divestiture scenario described in Section 5.2.3 requires the sale of MPA generating assets to CP&L and Duke Power. Since MPA ownership shares in three nuclear plants dominate those assets, we chose to focus on nuclear capacity as a proxy for the value of all the capacity owned by the MPAs. The first subsection of Appendix A details our method of approximating the value of that capacity. The main assumptions of that method are the following:

- The state of North Carolina assumes all liabilities associated with future decommissioning and decontamination costs for the MPA capacity.
- Today's best generation technology is a combined-cycle plant that costs about $643/kW.
- Our operating parameter and input cost estimates are reasonable for computing the capitalized value of future operating cost savings from operating a nuclear unit compared to a combined-cycle unit.
- Because of the absence of future cleanup liabilities, a nuclear unit is worth the sum of the current cost of a combined-cycle unit plus the capitalized value of the operating cost savings for the nuclear unit.

This valuation method produces a value of about $824/kW for nuclear units. To reflect the fact that some MPA capacity is coal-fired and due to the preliminary nature of this valuation, we rounded the value of MPA capacity down to $800/kW. Note that

this value is, nonetheless, more than 40 percent below the average book value of MPA capacity ($1,357/kW as shown in Table 2-3). It is also likely to be below the average book value of the nuclear capacity currently owned by CP&L and Duke—capacity for which they retain full liability for future cleanup.

The second subsection of Appendix A details the hypothetical sale of all the MPA generating assets to CP&L and Duke based on this estimate of capacity value. The scenario also assumes that the state provides 100 percent debt financing of this sale at an interest rate equal to the state's borrowing cost—an interest rate of about 4.95 percent. We added the capitalized value of this low-cost financing to the estimated market value of the generation capacity to compute a final sales price for the MPA generation assets. That final sales price is approximately $2.1 billion.

We further assumed that the state would liquidate the MPAs' invested funds to acquire an additional $1.7 billion. That revenue and the $2.1 billion sum to $3.8 billion, leaving a residual of about $2 billion in MPA debt.

Our final suggestion is that the state could impose electricity surcharges on the member cities to generate the necessary revenues to retire the additional $2 billion in debt (see Figure 5-3 for relationships between MPA surcharge rates and debt repayment). For example, we estimate that a surcharge of 2.6¢/kWh for 10 years would be sufficient to retire that amount of debt. Alternative surcharge rates and recovery periods are described in Appendix A.

This solution would result in electricity rates for the member cities that are about the same or possibly lower than they are now paying. Under this plan, they would pay the sum of competitive bulk power prices (now about 3.5¢/kWh), distribution costs averaging 1.75¢/kWh, and the surcharge of 2.6¢/kWh.[15] Their total average price would be about 7.85¢, which is approximately equal to their current retail prices and certainly at or below their projected retail prices in the next few years (see Figure 2-8).[16]

[15]This assumes that the surcharge rate is computed by blending the surcharge revenues for both MPAs. Separate accounting would require more detailed analysis.

[16]This rate of 7.85¢ is about 0.6¢ below the projected 1999 rate for NCEMPA customers and about 0.2¢ higher than the projected 1999 rate for NCMPA1.

Another option is to require CP&L and Duke to purchase the MPA capacity with their own financing so that the state would not be required to securitize much of the MPA debt. At the same time, the state could serve notice of the expected date when competition in generation services will begin and require CP&L and Duke to recover all their stranded costs (including any associated with this purchase) prior to the onset of competition. The notice would be accompanied by a deadline for their filing of a rate case before the NCUC for any rate changes needed to ensure recovery of their stranded costs. See Section 5.1.2 for more details on this concept.

5.3.3 Dissolution Scenario

The Dissolution scenario requires the same transfer of generation assets as the Divestiture scenario, but it also requires that CP&L and Duke purchase the complete electricity distribution systems owned by all of the member cities. Another alternative mentioned in Section 5.1.2 is to require the sale of NCEMPA member city systems within the boundaries of North Carolina Power to them, instead of CP&L—possibly for the sake of efficiency in electric service delivery.

We speculated that the 51 member city electric systems might be worth about $800 million. Then we added to that the value of low-cost financing of the purchase to obtain a projected sales price of about $1.3 billion. The third subsection of Appendix A details these calculations.

As was the case for our Divestiture scenario, we assumed that the sale of the generating assets would raise about $2.1 billion, and that the state would liquidate the MPAs' invested funds to acquire an additional $1.7 billion. That revenue and the $1.3 billion sale of the municipal systems add to $5.1 billion, leaving a residual of about $700 million in MPA debt.

We suggest that the $700 million of residual debt could be retired by revenue from electricity surcharges for the former customers of the member cities. (Alternatively, the member cities could pay this amount with revenue from new municipal bond issues, added

As detailed in Figures 2-5 and 2-6, those rates are below retail cost due to "buydowns" from the MPA's Rate Stabilization Funds. Because those funds are being depleted, and for other reasons, future MPA rates are expected to rise as detailed in Section 2.4.3 and Figure 2-8.

property taxes, or other options mentioned in Section 5.1.1.) For example, a surcharge of 0.9¢/kWh for 10 years would be sufficient to repay this amount of debt (see Figure 5-3). Alternative surcharge rates and recovery periods are described in Appendix A.

This solution would also lower or maintain current electricity rates for the member cities' customers compared to what they are now paying. Under this scenario they would pay the sum of the retail prices charged by CP&L or Duke, roughly 7.5¢/kWh, and the surcharge of 0.9¢/kWh. Their total average price would be about 8.4¢/kWh, which is near their projected retail prices in the next few years (see Figure 2-8).[17]

Again, the state has the option of requiring CP&L and Duke (and possibly North Carolina Power) to purchase the MPA capacity and the municipal electric systems with their own financing. This would allow the state to avoid securitizing much, if any, of the MPA debt. Likewise, the state could serve notice of a timeline for retail competition and set a deadline for IOU rate case filings to recover all their stranded costs (including any associated with this purchase) prior to the onset of competition. See Section 5.1.2 for more details on this concept.

It seems unlikely that any costs associated with the purchase of the member cities' electric systems would be considered stranded costs. All those costs would normally become part of the rate base for the combined distribution system of each company. We expect that distribution systems will continue to be subjected to the usual rate-of-return regulation even after the onset of retail competition for generation services. This should assure the purchasing IOUs of adequate returns on those incremental investments in member cities' electric systems.

5.4 SUMMARY AND CONCLUSIONS

Fortunately, the state of North Carolina and the stakeholders affected by the MPA debt problem have many reasonable options for resolving the problem. Each option imposes a burden on all

[17]This rate of 8.4¢ is a little above the projected 1999 rate of 7.63¢ for NCMPA1. But, again, that rate includes the effects of disbursements from the Rate Stabilization Funds. And, in any case, future rates are expected to rise for both MPAs as discussed in Section 2.4.3.

stakeholders, but the burden to individual stakeholders varies significantly among the options.

We have identified four policy options that we call the Status Quo, Debt Relief, Divestiture, and Dissolution. The Status Quo maintains current institutional arrangements and management of the assets now controlled by the MPAs and their member cities. It is a policy that portends increasingly difficult circumstances for the MPA member cities in the years ahead, particularly if and when the state moves to retail competition for generation services. The main reason is that the cost of bulk power at wholesale is already at least 30 percent below the MPAs' cost for producing bulk power. Even more unsettling is that the MPAs' costs are projected to rise by 30 percent over the next 15 years.

Each of the other three policy options that we have offered represents a full menu of variations. Each option has a large number of attributes, and each attribute can be selected from among several alternatives. For example, Divestiture calls for the sale of MPA generation assets and could require any of a number of financing alternatives, cost-sharing arrangements for the payment of MPA debt remaining after the asset sales, and methods of payment of those assigned cost shares, and so on.

The three alternative policy options are qualitatively different from each other in terms of the institutional arrangements and control of the electric system assets now owned by the MPAs and their member cities. Variations of the Debt Relief policy are closest to those that have been advanced by ElectriCities (e.g., electricity surcharges and price freezes). None of the Debt Relief options involve much change in the ownership and control of MPA and member city assets, except for possible changes in the governance of the MPAs.

To provide a full view of possible alternative policies, we did not restrict our attention to those that preserve the MPAs or member city ownership of their electric systems. Accordingly, we examined the Divestiture option, which entails the disposition of all MPA generating assets as well as fundamental changes in the role and operations of the MPAs. Beyond that, we examined the Dissolution option, which would also involve disposition of the MPA generating assets. In addition, it would require the sale of

most or all of the member city electric systems to North Carolina IOUs.

Our review of the four policy options uses three levels of exposition. First, Section 5.1 provides a fairly comprehensive, but general, discussion of the four options. That discussion describes many alternative potential sources of revenue to retire the MPA debt and characterizes several possible variations of the features that could be incorporated in the three policies that represent alternatives to the Status Quo.

Our second level of exposition develops and illustrates a structure for completing a *qualitative* analysis of the three policy alternatives. Section 5.2 defines specific versions of each of the three policy alternatives—Debt Relief, Divestiture, and Dissolution. One or more of these versions may, with some added refinement, be sensible options for further examination. The next part of Section 5.2 identifies seven groups of affected stakeholders: member cities,

- MPAs,
- IOUs,
- other North Carolina electric suppliers,
- the state of North Carolina,
- MPA bondholders, and
- the federal government.

Each of the organizations in this list of stakeholders represents both the organization and all the individuals they serve or employ. For each of these stakeholder groups, we qualitatively detail the prospective advantages and disadvantages to them of implementing each policy alternative. We recommend this model of qualitative analysis for any other policy variations that the Study Commission and stakeholders may wish to consider.

Our third level of exposition provides a *quantitative* analysis of the possible implementation of the three specific policy alternatives. In the quantitative analysis, we show how each of the policies could be structured and how the costs would vary for each of the major stakeholders.

Although the MPA debt problem may seem overwhelming, it is encouraging that the state has a large number of reasonable policy options to resolve the problem, as identified in this report. Some of the options that we identify seem more politically balanced than others in terms of the relative sacrifices required of the various stakeholder groups. But we do not advocate any of the alternative policies. Instead, we have sought to identify a rich set of options and demonstrate methods for analyzing them. The most important part of any future analyses is to determine carefully the advantages and disadvantages, both qualitatively and quantitatively, for each of the policy options within each stakeholder group. It is the role of the Study Commission and the major stakeholders to weigh these advantages and disadvantages and to choose a policy option that, in their judgment, maximizes fairness to all North Carolina citizens and enhances the efficiency of electric service delivery in the state.

Appendix A: Implementation Scenario Details

This appendix details the calculations discussed in Section 5.3, Implementation Scenarios. The first subsection discusses our valuation of MPA generation capacity; the second, our estimates of asset sales prices and surcharge calculations for the Divestiture scenario; and the third, similar estimates for the Dissolution scenario.

A.1 VALUATION OF MPA GENERATION CAPACITY

As described in Section 5.3.2, our method of approximating the value of MPA generation capacity incorporates several assumptions. The main ones are that the state of North Carolina retains all future liabilities for nuclear plant decontamination and decommissioning, and that such plants are worth as much as a combined-cycle plant plus the capitalized value of the lower operating costs of nuclear capacity.

Table A-1 details our calculations. Section A of the table shows our estimates of both the purchase costs and the running costs for a combined-cycle plant. The table includes the formulas and parameters we used in our calculations. Section B of the table shows parameter assumptions and calculations of running costs for a nuclear unit. Section C calculates the capitalized value of the difference in running costs for nuclear units versus combined-cycle units and adds that to the purchase cost for a combined-cycle unit to approximate the value of a nuclear unit.

A.2 DIVESTITURE SCENARIO

Table A-2 details the sale of MPA generation assets and the disposition of MPA debt. Section A of the table shows how we arrived at a sale price of about $2.1 billion for the generation assets. We rounded the value of capacity down to $800/kW to reflect the fact that some MPA capacity is coal-fired and due to the preliminary nature of the valuation in Section A.1. Section B calculates the residual MPA debt after accounting for the sale of generation assets and the liquidation of the MPAs' invested funds. Section C derives the alternative electricity surcharges for the

Table A-1. Hypothetical Valuation of Nuclear Capacity

A.	Competing Investment (Combined-Cycle Plant, CC)	
A.1	Capital Cost, $/kW	$643
A.2	Heat Rate (Btu/kWh) at 48.8% Efficiency	6,995
A.3	Annual Fixed Oper. & Maint. (O&M) Cost, $/kW	$30.32
A.4	Non-fuel Variable O&M Cost, ¢/kWh	0.0458
A.5	Fuel Variable Costs, ¢/kWh (=$2.657/mmBtu)*(A.2)*unit conversion factors)	1.86
A.6	Capacity Factor, % of year operated	60%
A.7	Annual kWh Production per kW Capacity (=8,760 hrs. * A.6)	5,256
A.8	Annual Non-fuel Variable O&M Cost, $/kW (=A.7 * A.4 * 100)	$2.41
A.9	Annual Fuel Costs, $/kW (=A.7 * A.5 / 100)	$97.76
A.10	Annual Total Running Costs, $/kW (=A.3 + A.8 + A.9)	$130.49
B.	Nuclear Plant, Stripped of Uninsured D&D Liability	
B.1	Fuel + Non-fuel Variable + Ann. Fixed O&M, ¢/kWh	1.51
B.2	Capacity Factor, % of year operated	83%
B.3	Annual kWh Production per kW Capacity (=8,760 hrs. * B.3)	7,271
B.4	Annual Total Running Costs, $/kW (=B.3 * B.1 / 100)	$109.79
C.	Valuation	
C.1	Annual CC Running Cost Premium, $/kW (=A.10 – B.4)	$20.70
C.2	Discount Factor (=((1–(1+int)**–T)/ int, int. = interest rate = 10.5%, and T = time horizon = 25 yrs.)	8.739
C.3	Present Value of Running Cost Difference (=C.1 * C.2)	$180.90
C.4	Purchase Cost for Competing Technology, (=A.1)	$643
C.5	Nuclear Unit Value, $/kW (=C.3 + C4)	$823.90

member cities that would be adequate to retire the residual debt (i.e., the debt that would remain after accounting for the asset sales and liquidations).

A.3 DISSOLUTION SCENARIO

Table A-3 reports our calculations for the Dissolution scenario. Section A of the table computes the sale price for the member cities' electric systems, including the capitalized value of low-cost debt financing. Section B of the table shows how the liquidation of invested MPA funds and the sales of both the MPA assets and the

Table A-2. Hypothetical MPA Debt Retirement: Divestiture

A.	Generation and Other MPA Asset Sales	
A.1	Available Generating Asset Capacity, Megawatts[a]	1,487
A.2	Approximate Market Value of Generating Assets ($/kW)[b]	$800
A.3	Total Generation Sale Value, $millions (=A.1 * A.2 / 1000)	$1,189
A.4	Other MPA Property & Operating Assets, $millions[c]	$110
A.5	Total Market Value of MPA Assets (=A.3 + A.4)	$1,299
A.6	Annual Pmt. On Market Value @10.5%, 25 years, $millions	$149
A.7	Present Value of Ann. Pmts. from A.6 @ 4.95%, 25 years, $millions	2,106
A.8	Value of Low Cost Debt Financing (=A.7 – A.5), $millions	$807
A.9	Sale Price, $millions (=A.8 + A.5)	$2,106
B.	MPA Asset Sales Revenue	
B.1	Total MPA Debt, $millions	$5,800
B.2	Less: Generation and Other MPA Asset Sales	$(2,106)
B.3	Less: Liquidation of Invested MPA Funds, $millions	$(1,739)
B.4	Residual MPA Debt, $/kW (=B.1 – B.2 – B.3)	$1,955
C.	MPA Member City Surcharges	
C.1	Present Value of Member City Electricity Surcharges, $millions Surcharge: 3.5¢/kWh, 7 yrs., 4.15% gvt. rate ***OR*** Surcharge: 2.6¢/kWh, 10 yrs., 4.15% gvt. rate ***OR*** Surcharge: 1.85¢/kWh, 15 yrs., 4.15% gvt. rate	$1,955
C.2	Residual MPA Debt, $millions (=B.4 – C.1)	zero

[a]Table 2-1.

[b]Round value from Table A-1.

[c]Asset category 2, Table 2-2.

member city electric systems reduce the MPA debt. Section C of the table reports alternative electricity surcharges on former MPA member city customers that will retire the residual debt.

Table A-3. Hypothetical MPA Debt Retirement: Dissolution

A.	Distribution Asset Sales		
	A.1	Market Value of Distribution Assets, $millions[a]	$800
	A.2	Annual Pmt. On Market Value @10.5%, 25 years, $millions	$92
	A.3	Present Value of Ann. Pmts. from A.2 @ 4.95%, 25 years, $millions	$1,297
	A.4	Value of Low Cost Debt Financing (=A.3 – A.1), $millions	$497
	A.5	Sale Price, $millions (=A.4 + A.1)	$1,297
B.	MPA Asset Sales Revenue		
	B.1	Total MPA Debt, $millions	$5,800
	B.2	Less: Generation and Other MPA Asset Sales	$(2,106)
	B.3	Less: Distribution Asset Sales	$(1,297)
	B.4	Less: Liquidation of Invested MPA Funds, $millions	$(1,739)
	B.5	Residual MPA Debt, $millions (=B.1 – B.2 – B.3 – B.4)	$658
C.	MPA Member City Surcharges		
	C.1	Present Value of Member City Electricity Surcharges, $millions Surcharge: 1.65¢/kWh, 5 yrs., 4.15% gvt. rate ***OR*** Surcharge: 1.2¢/kWh, 7 yrs., 4.15% gvt. rate ***OR*** Surcharge: 0.9¢/kWh, 10 yrs., 4.15% gvt. rate	$658
	C.2	Residual MPA Debt, $millions (=B.4 – C.1)	zero

[a]Figure 3-13.